SANDIA REPORT

SAND2017-0599
Unlimited Release

December 2016

Well Integrity for Natural Gas Storage in Depleted Reservoirs and Aquifers

Barry Freifeld[1], Curtis Oldenburg[1], Preston Jordan[1], Lehua Pan[1],
Scott Perfect[2], Joseph Morris[2], Joshua White[2],
Stephen Bauer[3], Douglas Blankenship[3], Barry Roberts[3],
Grant Bromhal[4], Deborah Glosser[4], Douglas Wyatt[4], Kelly Rose[4]

[1]Lawrence Berkeley National Laboratory, 1 Cyclotron Road, Berkeley, CA 94720
[2]Lawrence Livermore National Laboratory, 7000 East Avenue, Livermore, CA 94550
[3]Sandia National Laboratories, 1515 Eubank, Albuquerque, NM 87123
[4]U.S. Department of Energy, National Energy Technology Laboratory, 3610 Collins Ferry Road, Morgantown, WV 26507; 1450 Queen Avenue SW, Albany, OR 97321

Prepared By
Sandia National Laboratories
Albuquerque, New Mexico 87185 and Livermore, California 94550

Sandia National Laboratories is a multi-mission laboratory managed and operated by Sandia Corporation, a wholly owned subsidiary of Lockheed Martin Corporation, for the U.S. Department of Energy's National Nuclear Security Administration under contract DE-AC04-94AL85000.

Approved for public release; further dissemination unlimited.

Disclaimer

This document was prepared as an account of work sponsored by the United States Government. While this document is believed to contain correct information, neither the United States Government nor any agency thereof, nor The Regents of the University of California, nor any of their employees, makes any warranty, express or implied, or assumes any legal responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by its trade name, trademark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof, or The Regents of the University of California. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof or The Regents of the University of California.

This work performed under the auspices of the U.S. Department of Energy by Lawrence Berkeley National Laboratory under Contract DE-AC02-05CH11231, Lawrence Livermore National Laboratory under Contract DE-AC52-07NA27344, Sandia National Laboratories under Contract DE-AC04-94AL85000 and the National Energy Technology Laboratory.

Suggested Citation: Freifeld, B.; Oldenburg, C.; Jordan, P.; Pan, L; Perfect, S.; Morris, J.; White, J.; Bauer, S.; Blankenship, D.; Roberts, B.; Bromhal, G.; Glosser, D.; Wyatt, D.; Rose, K. *Well Integrity for Natural Gas Storage in Depleted Reservoirs and Aquifers*; SAND2017-0599

Well Integrity for Natural Gas Storage in Depleted Reservoirs and Aquifers

SAND2017-0599

Well Integrity Working Group

Barry Freifeld[1], Curtis Oldenburg[1], Preston Jordan[1], Lehua Pan[1], Scott Perfect[2], Joseph Morris[2], Joshua White[2], Stephen Bauer[3], Douglas Blankenship[3], Barry Roberts[3], Grant Bromhal[4], Deborah Glosser[4], Douglas Wyatt[4], Kelly Rose[4]

[1]Lawrence Berkeley National Laboratory, 1 Cyclotron Road, Berkeley, CA 94720

[2]Lawrence Livermore National Laboratory, 7000 East Avenue, Livermore, CA 94550

[3]Sandia National Laboratories, 1515 Eubank, Albuquerque, NM 87123

[4]U.S. Department of Energy, National Energy Technology Laboratory, 3610 Collins Ferry Road, Morgantown, WV 26507; 1450 Queen Avenue SW, Albany, OR 97321

LBNL-1006165

NETL-TRS-15-2016

16 December 2016

This page intentionally left blank.

This page intentionally left blank.

Table of Contents

ABSTRACT **1**

1. INTRODUCTION **2**
1.1 MOTIVATION 2
1.2 FEDERAL REVIEW OF WELL INTEGRITY 2
1.3 BACKGROUND ON THE DOE NATIONAL LABORATORIES WELL INTEGRITY WORK GROUP 2
1.4 TASKS OF THE WELL INTEGRITY WORK GROUP 2
1.5 PURPOSE OF THIS REPORT 3

2. BRIEF PRIMER ON NATURAL GAS STORAGE IN THE U.S **4**
2.1 WHY IS NATURAL GAS STORED UNDERGROUND? 4
2.2 HOW IS NATURAL GAS STORED? 4
2.3 WHERE IS NATURAL GAS BEING STORED? 4
2.4 WHY DO WE CARE ABOUT NATURAL GAS LEAKS? 5

3. TASK 1. GAS STORAGE WELL INTEGRITY WORKSHOP **7**
3.1 INTRODUCTION 7
3.2 WORKSHOP SUMMARY 7

4. TASK 2. CIRCUMSTANCES SURROUNDING ALISO CANYON EVENT **22**
4.1 INTRODUCTION 22
4.2 STANDARD SESNON 25 WELL HISTORY 24
4.3 GENERAL OPERATIONAL HISTORY OF STANDARD SESNON 25 26
4.4 STANDARD SESNON 25 WELL LOGGING 29
4.5 SUMMARY OF SUBSURFACE SAFETY VALVE USE AT ALISO CANYON GAS STORAGE FACILITY 31
4.6 EMERGENCY RESPONSE (TOP KILL ATTEMPTS) 36
4.7 MONITORING AND LEAK DETECTION (AT SURFACE AND/OR BELOW GROUND) 37
4.8 SUMMARY AND CONCLUSIONS 38

5. TASK 3. REGULATORY REVIEW AND THE POTENTIAL FOR PROBLEMS AT OTHER STORAGE SITES **40**
5.1 INTRODUCTION 40
5.2 REGULATION OF NATURAL GAS STORAGE FACILITIES 41
5.3 REVIEW OF CURRENT STATE REGULATIONS RELATED TO GAS STORAGE FACILITIES 43
5.4 GAS STORAGE WELLS IN THE UNITED STATES – DATA AND ANALYSIS 49

6. TASK 4. RECOMMENDATIONS AND CONCLUSIONS **61**
6.1 TOPIC I. WELL INTEGRITY RECOMMENDATIONS 61
6.2 TOPIC II. RISK MANAGEMENT RECOMMENDATIONS 64
6.3 TOPIC III. RESEARCH AND DATA GATHERING RECOMMENDATIONS 66

7. REFERENCES **70**

APPENDIX: REQUIREMENTS OF COMPREHENSIVE SAFETY REVIEW OF ALISO CANYON NATURAL GAS STORAGE FACILITY **A-1**

This page intentionally left blank.

List of Figures

Figure 1: Types and count of underground gas storage facilities in the United States (U.S. EIA, 2016b).....5
Figure 2: Timeline of Aliso Canyon Events. 22
Figure 3: Layout and age distribution of Aliso Canyon storage wells. 23
Figure 4: SS-25 well schematic. 24
Figure 5: Timeline of major events for Standard Sesnon 25 well. 26
Figure 6: Casing and tubing production pressure history curves for Standard Sesnon 25. 27
Figure 7: Scatter plot of casing versus tubing pressures. 28
Figure 8: Surface injection pressures for Standard Sesnon 25. 29
Figure 9: Timeline of well logging activities for Standard Sesnon 25 during gas storage. 31
Figure 10: Vent crater caused by expulsion of top kill attempt materials. 36
Figure 11: SS-25 top kill failure scenario. 37
Figure 12: Aliso Canyon Well Logging Timeline. 38
Figure 13: Types and count of gas storage facilities in the United States (U.S. EIA, 2016b). 41
Figure 14: 2012 state level natural gas storage capacity (mcf) by reservoir type (U.S. EIA, 2016a). 45
Figure 15: Number of natural gas storage wells permitted per decade. 50
Figure 16: Gas storage wells by year and depth below surface (ft) n=9,771. 51
Figure 17: Number of natural gas storage wells in each state, broken out by drilling status. 52
Figure 18: Spatial analysis of natural gas wells. 53
Figure 19: Number of hydrocarbon fields associated with gas storage wells, by state. 54
Figure 20: Analysis of initial use and number of wells in gas storage fields by state. 54
Figure 21: Population centers within 5 km of an active natural gas storage well. 56
Figure 22: Natural gas well proximity to human population centers. 57
Figure 23: Percent change in Pennsylvania county level population, and the locations of active storage fields during that time period. 59
Figure 24: Changes in census tract level population density near gas storage facilities, 1970 and 2010. 60

List of Tables

Table 1: Original installed casing for Standard Sesnon 25 25

Table 2: Standard Sesnon 25 Well Log History (after conversion to gas storage through 2015) 30

Table 3: Summary of Aliso Canyon Gas Storage Facility Well Configurations 32

Table 4: API Numbers for SoCal Gas Aliso Canyon Gas Storage Wells 32

Table 5: States with regulations addressing underground natural gas storage based on storage type. Based on analysis by Ground Water Protection Council (2016); The Revisor of Statutes, State of Minnesota (2015). This subset of 19 states were chosen for analysis because 90% of all natural gas storage wells are located in these states. Note: this is not an exhaustive list. This subset of 19 states were chosen for analysis because 90% of all natural gas storage wells are located in these states. States not on this list may or may not have regulations. 43

Table 6: States with regulations regarding natural gas storage well construction, maintenance, and plugging and abandonment as of August 2016. The California regulations are interim emergency regulations (Ground Water Protection Council, 2016; The Revisor of Statutes, State of Minnesota, 2015; State of Iowa, 2016). 47

Table 7: Calculated failure rates for catastrophic well failure. Reproduced from Table 6 in Health and Safety Laboratory (2008) 49

Acronyms, Abbreviations, and Symbols

Term	Description
AGA	American Gas Association
ALARP	As Low As Reasonably Practicable
API	American Petroleum Institute
CIG	Colorado Interstate Gas Company
DHSV	Downhole Safety Valve
DOC	U.S. Department of Conservation
DOE	U.S. Department of Energy
DOGGR	Division of Oil, Gas, and Geothermal Resources
DOT	U.S. Department of Transportation
EDF	Environmental Defense Fund
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
FE	Fossil Energy
FERC	Federal Energy Regulatory Commission
ft	Feet
IoT	Internet of Things
LBNL	Lawrence Berkeley National Laboratory
LLNL	Lawrence Livermore National Laboratory
mcf	Million cubic feet
MIT	Mechanical Integrity Testing
MTTF	Mean Time to Failure
NATCARB	National Carbon Sequestration Database and Geographic Information System
NETL	National Energy Technology Laboratory
NGA	Natural Gas Act
NGPSA	Natural Gas Pipeline Safety Act
NGS	Natural Gas Storage
PHMSA	Pipeline and Hazardous Materials Safety Administration
PIPES Act	PIPES Act
ppf	Pound per foot
SNL	Sandia National Laboratories
SSSVs	Subsurface Safety Valves

Acronyms, Abbreviations, Symbols (cont.)

Term	Description
SSVs	Sliding Sleeve Valves
TCF	Trillion cubic feet
TOC	Top-Of-Cement

Acknowledgments

This work was performed by Lawrence Berkeley National Laboratory (LBNL) under Contract DE-AC02-05CH11231, Lawrence Livermore National Laboratory (LLNL) under Contract DE-AC52-07NA27344, Sandia National Laboratories (SNL) under Contract DE-AC04-94AL85000, and the National Energy Technology Laboratory (NETL). This work was completed with support from the U.S. Department of Energy's (DOE) Office of Fossil Energy Oil & Gas Program. The authors wish to acknowledge Lynn Orr, Tarak Shah, Neelesh Nerurkar, Guido DeHoratiis, Christopher Freitas, Rob Vagnetti, and Jared Ciferno for programmatic guidance, direction, and support.

This page intentionally left blank

ABSTRACT

Natural gas storage facilities are a critical component of our energy supply and distribution chain, allowing elasticity in gas supply to accommodate daily to seasonal demand fluctuations. As has been made evident by the recent Aliso Canyon Gas Storage facility incident, a loss of well integrity may result in significant consequences, including the prolonged shutdown of an entire facility. The Aliso Canyon gas well blowout emitted approximately 100,000 tonnes of natural gas (mostly methane) over 4 months and displaced thousands of nearby residents from their homes. The high visibility of the event has led to increased scrutiny of the safety of natural gas storage at the Aliso Canyon facility, led to questions about energy reliability, and raised broader concerns for natural gas storage integrity throughout the country.

This report contains the results of a review of issues surrounding well integrity and natural gas storage. The report summarizes the presentations and discussions from a Well Integrity Workshop, held July 12–13, 2016 in Broomfield, Colorado. Attending the Workshop were nearly 200 regulators, operators and technical specialists. The report examines the circumstances surrounding the Aliso Canyon event and provides an analysis of the current regulatory and technological landscape for our national natural gas storage infrastructure. Finally, the report concludes with recommendations for improving gas storage well integrity and reducing the likelihood of future adverse events.

1. INTRODUCTION

1.1 MOTIVATION

The 2015–2016 Aliso Canyon/Porter Ranch natural gas well blowout emitted approximately 100,000 tonnes of natural gas (mostly methane, CH_4) over 4 months. The blowout impacted thousands of nearby residents, who were displaced from their homes. The high visibility of the event has led to increased scrutiny of the safety of natural gas storage at the Aliso Canyon facility, as well as broader concern for natural gas storage integrity throughout the country.

1.2 FEDERAL REVIEW OF WELL INTEGRITY

In April of 2016, the U.S. Department of Energy (DOE), in conjunction with the U.S. Department of Transportation (DOT) through the Pipeline and Hazardous Materials Safety Administration (PHMSA), announced the formation of a new Interagency Task Force on Natural Gas Storage Safety. The Task Force enlisted a group of scientists and engineers at the DOE National Laboratories to review the state of well integrity in natural gas storage in the U.S. The overarching objective of the review is to gather, analyze, catalogue, and disseminate information and findings that can lead to improved natural gas storage safety and security and thus reduce the risk of future events. The "Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016'' or the ''PIPES Act of 2016,''which was signed into law on June 22, 2016, created an Aliso Canyon Natural Gas Leak Task Force led by the Secretary of Energy and consisting of representatives from the DOT, Environmental Protection Agency (EPA), Department of Health and Human Services, Federal Energy Regulatory Commission (FERC), Department of Commerce and the Department of Interior. The Task Force was asked to perform an analysis of the Aliso Canyon event and make recommendations on preventing similar incidents in the future. The PIPES Act also required that DOT/PHMSA promulgate minimum safety standards for underground storage that would take effect within 2 years.

1.3 BACKGROUND ON THE DOE NATIONAL LABORATORIES WELL INTEGRITY WORK GROUP

One of the primary areas that the Task Force is studying is integrity of natural gas wells at storage facilities. The DOE Office of Fossil Energy (FE) took the lead in this area and asked scientists and engineers from the National Energy Technology Laboratory (NETL), Lawrence Livermore National Laboratory (LLNL), Sandia National Laboratories (SNL), and Lawrence Berkeley National Laboratory (LBNL) to form a Work Group to address this area. This Work Group is an expansion of the original "Lab Team" comprising scientists and engineers from SNL, LLNL, and LBNL which was formed to support the State of California's response to the Aliso Canyon incident and operated under the Governor of California's Aliso Canyon Emergency Order (1/6/2016). The Lab Team played a key role in advising the State of California's Department of Conservation (DOC) in its oversight of SoCalGas during and after the incident.

1.4 TASKS OF THE WELL INTEGRITY WORK GROUP

Building upon its experience with the Aliso Canyon incident and long history with reservoir integrity science and technology, the Lab Team joined with experts from NETL to lead the Interagency Task Force in accomplishing the following tasks:

Task 1. Organize, host, and run a national workshop on gas storage well integrity

Task 2. Analyze the Aliso Canyon event and surrounding circumstances

Task 3. Evaluate potential for problems at other storage sites

Task 4. Provide recommendations for reducing future risks

1.5 PURPOSE OF THIS REPORT

This report presents the findings of the DOE National Laboratories Well Integrity Work Group efforts in the four tasks. In addition to documenting the work of the Work Group, this report presents high priority recommendations to improve well integrity and reduce the likelihood and consequences of subsurface natural gas leaks.

2. BRIEF PRIMER ON NATURAL GAS STORAGE IN THE U.S.

2.1 WHY IS NATURAL GAS STORED UNDERGROUND?

Natural gas has been an important commodity in the United States and the world, particularly for heating and for power generation. Underground natural gas storage is used in the transportation and delivery of gas by pipeline to end users. For example, gas storage facilities provide quick access to large volumes of gas for end users during periods of high demand, such as during a cold spell in the winter or a period of high electricity demand in the summer (U.S. EIA, 2016b). Approximately 4 TCF of gas is contained in working gas storage capacity, and the annual summer/winter cycles sees a withdrawal of more than 2.5 TCF (AGA, 2016), making gas storage an integral part of our energy delivery system.

2.2 HOW IS NATURAL GAS STORED?

Natural gas is injected through wells into a subsurface geological formation. As gas is injected, pressure builds within the formation. Higher reservoir pressures allow higher storage volumes and greater gas flow volume during the extraction part of the storage cycle to help ensure suitable production rates (Niska, 2010). Typically, vertical wells are used to inject and withdraw the gas, though horizontal wells are becoming more common.

In underground storage facilities, a significant portion of the gas that is injected initially will remain in the subsurface, and will not be produced during a typical withdraw cycle. This gas is commonly known as "base gas" or "cushion gas," and is intended as a permanent inventory in a storage reservoir that is needed to maintain adequate pressure, minimize concomitant water production, and sustain deliverability rates throughout the withdrawal season. (U.S. EIA, 2016b)

More about how natural gas storage fields work can be found in the Niska Gas Storage Industry Primer (2010) and from the U.S. EIA's *Natural Gas Underground Storage Facilities* (2016b).

2.3 WHERE IS NATURAL GAS BEING STORED?

Underground natural gas storage is found in three main types of storage formations: depleted oil and gas fields, aquifers, and salt caverns. These storage facilities can be found across the United States in approximately 415 facilities in over 25 states, as shown in Figure 1 (U.S. EIA, 2016b).

The most common type of underground gas storage field, by far, is the depleted oil and gas field. These fields typically have the benefit of having been relatively well characterized (e.g., measured and mapped) during oil and gas activities and having demonstrated an ability to contain hydrocarbons over geologic time. They also typically have the benefit of already containing some cushion gas from the production phase.

Aquifers account for about 10% of the UGS fields, and are similar to the oil and gas fields in the way they function, as porous permeable formations capable of holding and releasing fluids. Although aquifers are often more expensive to develop than depleted oil and gas fields, they are more common than oil and gas fields across the U.S., and can be found in locations that are useful for underground gas storage, such as proximal to but not too near population centers with high demand.

Salt caverns are significantly different than the other two types of storage formations. They are found in salt domes or salt beds, and they are usually solution mined by injecting fresh water,

dissolving the salt, and producing the saturated brine. The main benefit of the typical salt cavern is that they give a greater throughput, both in the injection and production cycles.

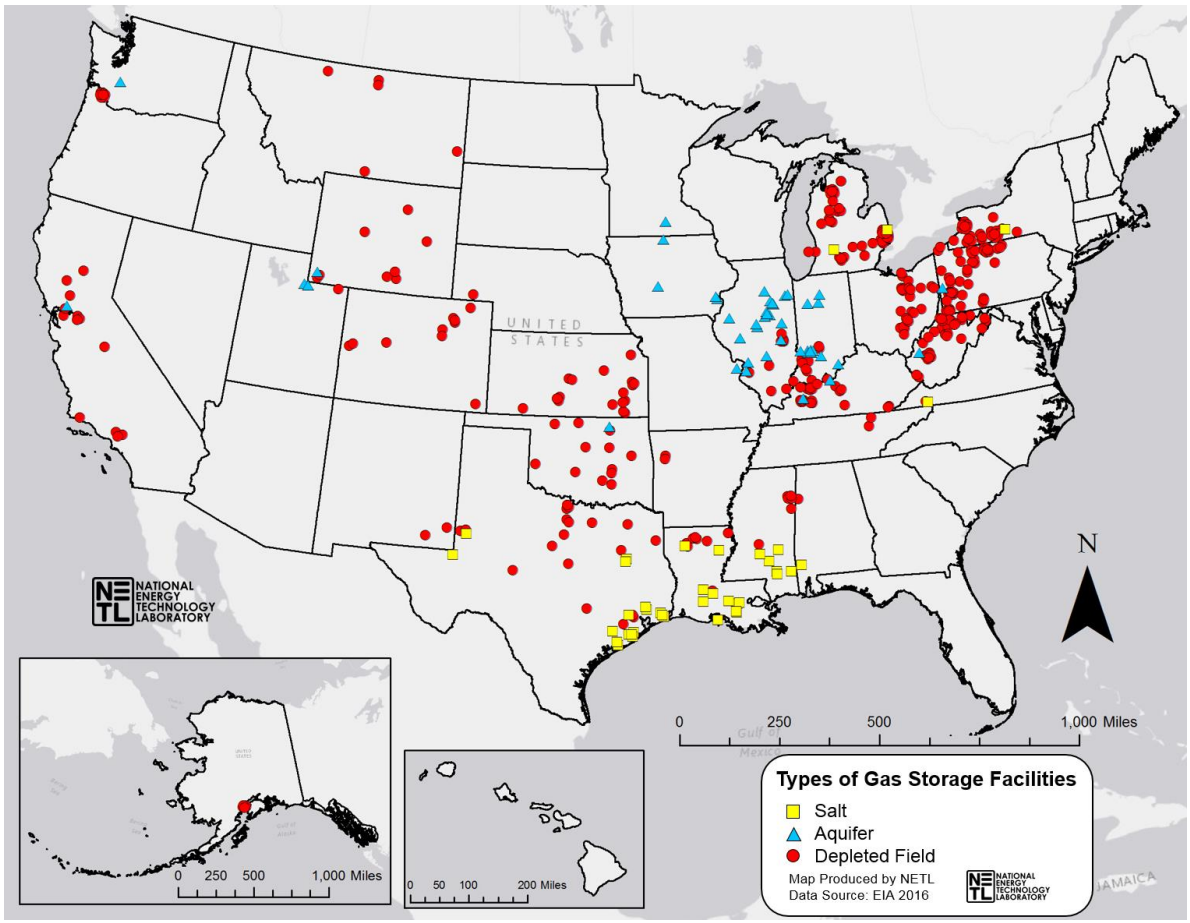

Figure 1: Types and count of underground gas storage facilities in the United States (U.S. EIA, 2016b).

2.4 WHY DO WE CARE ABOUT NATURAL GAS LEAKS?

Unlike some other types of fluids that are injected into the subsurface, natural gas is flammable, and can cause a considerable health and safety hazard if leaked in significant quantities and/or if leaks are unintentionally ignited. The Yaggy incident near Hutchinson Kansas in 2001, caused loss of property and life, and the Moss Bluff incident in Texas in 2004, caused an explosion that consumed around 6 billion cubic feet of natural gas. A leaky gas storage field can be a significant health and safety hazard, even if no property is damaged in an initial explosion. Natural gas may also contain hydrogen sulfide (H_2S), benzene, and natural gas odorants, which can cause health impacts.

One of the major problems with a gas leak is the loss of a valuable commodity. Sometimes, particularly with salt caverns, a large volume of gas must be spent or flared before the release can be brought under control. Methane is a significantly more potent greenhouse gas than carbon dioxide, on a per volume basis. Sizable releases of CH_4, such as the recent Aliso Canyon incident

in California, can contribute in a large way to climate change. Additionally, a large UGS failure may disrupt enough gas delivery service to cause energy reliability concerns, including potential electricity blackouts. Gas storage facilities are key components of a large and complex natural gas delivery infrastructure that serve homes, offices, power plants, and industrial facilities. Smooth functioning of that infrastructure is vital to our economy, our quality of life, and our national security.

More information about the numbers and types of gas storage formations, notable past leakage incidents, and statistics on the ages of natural gas storage infrastructure can be found in Section 5 (Task 3) of this report.

3. TASK 1. GAS STORAGE WELL INTEGRITY WORKSHOP

3.1 INTRODUCTION

The objective of the Natural Gas Storage Well Integrity Workshop was to assemble operators, regulators, and technical experts to examine the current state of natural gas storage wellbore integrity and to consider ways to improve the reliability of gas storage through improved subsurface practices. The workshop, held July 12–13, 2016 in Broomfield, Colorado, assembled approximately 200 people, including 65 operators, 39 regulators, and 51 industry, academic and national laboratory personnel. The 2-day forum consisted of presentations on risk management, construction practices, monitoring and testing of subsurface storage integrity, accident management (e.g., controlling leakage and blowouts), gaps in knowledge about wellbore integrity, and ways to improve the state of knowledge to address those gaps. There were also three panel/expert-led discussions addressing regulatory issues, performance of down hole safety valves and a general recap of open issues to conclude the meeting. The IOGCC Gas Storage Workgroup held a meeting on July 11 including participants from the National Laboratories and PHMSA in which they continued to organize the writing of a gas storage primer that would serve to guide regulatory agencies. PHMSA held a public forum on July 14 to solicit input for consideration in their rulemaking as they develop regulations for gas storage as is required by the PIPES Act of 2016.

3.2 WORKSHOP SUMMARY

The Workshop consisted of twenty-two presentations and three discussion sessions. The workshop was chaired by Barry Freifeld, LBNL, Stephen Bauer, SNL, Grant Bromhal, NETL, and Scott Perfect, LLNL. In addition to the workshop chairs, the steering committee included Larry Kennedy from Pacific Gas & Electric, Ken Harris from the State of California DOC/DOGGR, and Kenneth Lee from DOT/PHMSA. Opening remarks were provided by DOE Undersecretary for Science and Energy Franklin Orr and DOT/PHMSA Administrator Marie Therese Dominguez. Presenters were given the option to make their presentations publicly available. Twenty-one of twenty-three presentations were released on the Workshop website. Following the session descriptions below are hyperlinked references to the released presentations.

3.2.1 Session 1: Overview/Introductory Talks

Talks were provided by representatives of the AGA, IOGCC, and EDF to set the scene for further gas storage well integrity discussions and direction for regulatory review. The presentation from the AGA showed that of the 4 TCF in working gas storage capacity, the annual summer/winter cycles results in a withdrawal of ~2.5 TCF, making gas storage an integral part of our energy delivery system. The IOGCC presented their work in developing a gas storage primer that would serve as a road mapping and reference document to support regulatory agencies in overseeing gas storage subsurface infrastructure. The Environmental Defense Fund (EDF) presented an overview of regulatory elements for gas storage. The EDF indicated that ongoing efforts across the country are a welcome sign and posed three questions: How can PHMSA make use of state expertise especially given that congress has preempted state regulation of interstate facilities and given differences in well integrity rules across states?; At both state and federal levels, how will enhancements be funded?; noting that API RP 1170 and 1171 are explicitly not all-inclusive and that they supplement, rather than replace regulations, how can risk management

requirements be based on these documents without creating the situation that the industry is regulating itself? The EDF also highlighted 14 categories that the IOGCC primer will cover: permitting, well drilling and construction, well operation and maintenance, surface leak detection, inventory tracking, surface facility operation, reservoir integrity, monitoring, emergency response, plugging, temporary abandonment, and restoration, risk management, and public participation. These 14 categories were noted to contain more than 100 elements.

Session 1-1, Examining a Natural Gas Supply Pillar: Domestic Underground Storage, C. McGill, American Gas Association

Session 1-2, IOGCC Task Force on Well Integrity for Natural Gas Storage, R. Simmers, Ohio Department of Natural Resources

Session 1-3, Regulator Elements for Gas Storage, A. Peltz, Environmental Defense Fund

3.2.2 Session 2: Operators Presentations on Integrity Management

This session featured talks on risk management, integrity management, and a comparison of mechanical integrity testing (MIT) requirements across different states. One operator gave a detailed presentation describing the comprehensive asset and risk management plans the company uses for its gas storage facilities and pipelines. The operator employs the ISO 55001 framework for managing assets and bases its risk management plan on API RP 1171 and ASME B31.8S (CFR 40 Part 192 Subpart O). A key part of their approach is continuous improvement: defining a desired end state; developing metrics to measure performance and progress; and reviewing technology developments and investment decisions. Another key is that their asset management program is supported throughout the organization and involves participation at multiple levels including upper management. The audience asked several good questions. One questioner inquired how mature their processes are (well along, but a lot of room to grow and they will never consider them completed) and how long it took to get from starting point to current state (about 2 years, which required unwavering commitment from upper management).

One presenter described his company's integrity management program. This operator was asked to submit a revised operating plan in a short time span. Recognizing that they were responsible for over 500 wells, many of which were more than 50 years old, the operator determined that the request could best be met by establishing an electronic data management system. The operator installed a web-based system that stores and organizes all of its data and manages its processes. The system performs calculations, generates reports, and lets users visualize and edit information. The presenter explained the "proof of safety" approach that is used to demonstrate integrity. For example: the system calculates casing safety factors using present conditions and safety factors at the end of a defined operating period, assuming various corrosion/wear rates. These calculations are compared with inspection data to assess remaining wall thickness (casing life remaining). The software can roll-up the integrity assessments into a stoplight chart that highlights any need for intervention. This approach is seen as analogous to the data and records management that will be needed upon the promulgation of enhanced rules that require a reinvestigation of old wells.

It was stated many times during the workshop that risk/integrity management is resource-constrained. Operators have finite resources and they must plan their investments carefully. Risk mitigation is often viewed in terms of trade-offs: if an operator invests one place, it must forego

investment elsewhere. An operator's resources may be limited by rate regulation, market forces, shareholder interests, etc. There are limits to what can be achieved in a "zero-sum" environment.

Session 2-1, PG&E's Asset and Risk Management, L. Kennedy, PG&E

Session 2-2, Well Integrity Assessments – A Methodical Approach Applied to Numerous Gas Storage Wells, A. Bannach, ESK GmbH

Session 2-3, Comparison of MIT Testing Across a Variety of States, J. Wilson & B. Romo, Sabine Storage & Operations, Inc.

3.2.3 Session 3: Regulations and Standards

This session consisted of presentations that address regulations and regulatory frameworks. The introductory presentation looked at the evolution of technology and how it impacted oil and gas standards. It highlighted the difficulties in identifying old abandoned wells, which are a major risk element in areas with oilfield development prior to modern cement plugging and abandonment practices. Even wells that have been "properly" abandoned sometimes leak. A talk on UIC regulation impacts noted how the 1988 development of new rules by the EPA for hazardous waste disposal in wells had financially impacted operators, but at the same time prevented poor practices and improved public acceptance. Sharing information on design and construction standards was noted as a way to improve the entire UIC industry.

One talk that elicited strong feedback was the presentation concerning the development and adoption of API RP 1171. Many of the workshop participants were members of the Committee that developed API RP 1171 and they provided valuable insight into the thinking and decision-making of the Committee. API RP 1171 is a consensus standard and uses language (particularly the use of "should" or "may" versus "shall") that may have been determined using a voting procedure. A participant, who had been a Committee member, indicated that there are topics such as leak detection that were excluded from API RP 1171 because there was not a consensus of knowledge and experience sufficient to recommend good practice. Similarly, API RP 1171 discusses topics such as well monitoring methods but does not recommend specific practices/processes. The presenter indicated that the gas storage community is still in a learning phase with regard to integrity management and that he supports ongoing collaboration among operators, regulators, and other stakeholders to share information and lessons-learned that can be used to improve regulations, standards, and practices. He suggested (and others echoed this sentiment) that "risk-based" integrity management approaches are preferable to, and more effective than, "prescriptive approaches." He specifically advocated for "risk-based" monitoring over "time-based" monitoring. He stated that data should be collected at intervals determined using a process that considers risk, cost, reliability, etc.; not collected at prescribed time intervals.

The concept of *as low as reasonably practicable* or ALARP was introduced. Many people were unfamiliar with this term, which appears to be a variant of ALARA, "As Low as Reasonably Achievable." ALARA is used ubiquitously in the health physics field to mean that all reasonable methods are employed to minimize radiation exposure. Further review of the term ALARP finds that it comes from UK risk assessment terminology to mean what is practical when conditioned on an economic cost-benefit analysis. One issue with ALARP is that "practicable" is subject to interpretation. The essence of ALARP is that risks must be mitigated to a point where the costs of reducing risk further are grossly disproportionate to the benefits of doing so. This is mostly

consistent with other approaches that have been suggested but ALARP approaches risk management from a slightly different direction. ALARP takes the stance that further mitigation is needed until it can be shown that cost is grossly disproportionate to benefit. Someone, presumably the regulator, must determine what level of risk is ALARP.

The API/INGAA/AGA Integrity & Safe Operation report references the methodology of Powell and Van Scyoc (SPE #145428) to argue that a structured risk management approach requires more integrity management directed at higher risk wells. It was pointed out that API RP 1171 states that "This document is intended to supplement, but not replace, applicable local, state, and federal regulations." Given that PHMSA has requested that operators voluntarily follow API RP 1171, the above caveat was noted to result in a significant gap in the current situation, where adequate rules do not currently exist and industry recommendations are not viewed as a replacement for regulations. API RP 1170 & 1171 also include the recommendation for updating on a maximum 5-year cycle, so this can result in updated recommended practices by 2020.

The presentation by State of California Department of Conservation (DOC) Division of Oil, Gas, and Geothermal Resources (DOGGR) personnel on their proposed draft rules elicited the most feedback and discussion of the workshop.

Several workshop participants, including operators inside and outside of California, indicated that they believe the California draft regulations are a positive development. They suggested that the draft regulations provide a needed regulatory complement to API 1171 in that the draft regulations help to clarify the responsibilities of the operators and the regulators.

Some workshop participants suggested that the Draft Regulations are not sufficiently prescriptive. They suggested that regulations should thoroughly prescribe what is required and how each requirement must be met (for example, wells must undergo a specific set of tests and must meet specific performance metrics for these tests). The suggestion was typically accompanied by one of both of the following concerns: that the requirements might lack the technical basis and stakeholder vetting necessary to be considered relevant and cost-effective; that operators might be placed in a position where they must iterate with regulators because neither understands what is required.

The Draft Regulations are thought by many to be a stringent regulatory framework for gas storage and some operators felt challenged by both the required frequency of inspections and the well construction requirements. One independent system operator noted that the requirement to go to double barriers would force them to install liners or tubing and packers and result in a 40% reduction in deliverability with their current wells. Others noted that the flow reduction going from casing production to tubing production is not well quantified yet.

There was discussion on how the mechanics of a gas storage project would be developed under the rules, which requires DOC/DOGGR personnel to evaluate a project application and issue a project approval letter with conditions as appropriate. The draft rules also require periodic reviews to consider changed conditions and ensure no threat to life, health, property or natural resources. DOC/DOGGR invited the audience to attend their rulemaking public workshops in California on August 9 and 11.

Session 3-1, Regulatory, Commercial, and Science Insights for Gas Storage Well Integrity, D. Glosser, U.S. DOE, National Energy Technology Laboratory

Session 3-2, Class 1 UIC Regulations & Their Impact on Industries and Operators, D. Stehle, Geostock Sandia ?

Session 3-3, Peace and Revolution: The Creation of American Petroleum Institute (API) Natural Gas Storage Standards and the Dawn of Implementation, S. Nowaczewski, TransCanada

3.2.4 Session 4: The Aliso Canyon Event

Southern California Gas provided an overview of the Aliso Canyon event, its impacts and the program underway to get the facility operating again. The State of California DOC/DOGGR provided a view of the event from their perspective. They noted that more than 30 agencies were involved in the response. Lessons learned included: extremely high gas flow rates cause tool failures, liquid production, impacts to offset wells, etc. They recommended putting the fire department in charge of site access and ensuring that a robust communication system is established. They recommended the use of enforceable legal mechanisms such as orders. They suggested that formal roles such as POC need to be established early and the roles must be described in writing in a clear, concise manner. They also cautioned that politics will scale to size of the problem. Attached as the Appendix to this report are the guidelines that were established for resumption of service at Aliso Canyon. A presentation on earthquake hazards in the Aliso Canyon area identified risks that exist from active faults but noted that no impacts are known to have occurred from nearby earthquakes.

Session 4-1, The Aliso Canyon Incident, R. Schwecke, Southern California Gas Company

Session 4-2, California Division of Oil, Gas and Geothermal Resources, Response to the Aliso Canyon Event, R. Habel & A. Walker, DOGGR

Session 4-3, National Lab Activity Overview, S. Bauer, Sandia National Laboratories

Session 4-4, Well Integrity and Active Faulting, T.L. Davis, Geologist, Ventura, CA

3.2.5 Session 5: Well Integrity Management and Technology

This session featured talks from industry representatives on storage integrity management methods and technologies. The introductory talk on storage integrity management emphasized that a “one-size-fits-all” approach should be avoided, adding that each plan needs a macro and a micro approach, where the macro approach deals with reservoir integrity and management and the micro approach deals with individual wells. The second and third talks covered different integrity tools and techniques, focusing primarily on well logging and diagnostics for casing and cement. A new tri-axial magnetic flux leakage tool used for diagnosing casing in boreholes filled with gas (as compared to traditional methods which require liquid-filled boreholes) was discussed. Audience questions focused on accuracy, cost, and effectiveness of the tools compared to older technology. The final talk was provided by a well control specialist on emergency response methods for well blowouts and failures. The speaker made the point that every operator should have a well control and emergency plan in writing. An ICS 201 incident action plan and ICS 208 site safety plan should both be available and ready if needed. In the event of an incident, air monitoring needs to be set up to identify hazards before people can be sent in.

Session 5-1, Storage Integrity Management - Field and Well, J. Abraham, Questar Pipeline

Session 5-2, Well Integrity Evaluation – A Breakdown of Available Technology: Strengths, Weaknesses, and Applications, J.C. Pinkett, Halliburton Energy Services

Session 5-3, Innovative Cement and Casing Corrosion Evaluation Technologies Provide Reliable Well Integrity Information in Natural Gas Storage Wells, S. Kamgang, Baker Hughes

Session 5-4, Well Control Methods, C. Davis, Wild Well Control

3.2.6 Session 6: Discussion Session on "What Regulations are Needed for Ensuring Safe Storage?"

This session was kicked off by a talk on the Yaggy Incident in Kansas to set the scene for a discussion on the need for regulations. The Yaggy incident was a cavern storage well in which gas leaked from a breach in the casing and traveled several miles where it reached the surface in Hutchinson, Kansas. It was described as being as much a regulatory incident as a well control incident. The leak led to a catastrophic fire that destroyed several buildings and an explosion that killed two people.

Session 6-1, The Yaggy Incident, J. Ratigan, Ratigan Engineering & Consulting

Panel Discussion Notes. The following comments were made during the discussion session:

- **Question:** Where does the well integrity program fit into the whole scheme?
- **Question:** Intrastate versus interstate wells – what will the certification program for states look like?
    - Some will go beyond federal regulation and some will not. There is a need to ensure the combination of two sets of regulations is smooth
    - **Question:** Well Permitting, use of safety valves, etc. – where are there overlapping regulations and where are there gaps between the Pipeline and Hazardous Materials Safety Administration (PHMSA) and state regulations?
    - **Question:** In any given state, there could be two separate set of rules for intrastate versus interstate wells – does this make sense?
    - A way to get around discrepancies between intrastate and interstate regulations – In the risk management planning process, interstate wells should be managed so they consider and adhere to both intrastate and interstate regulations.
    - The process has been emulated in the past (1990s) – joint relationship between state and federal parts with a common set of minimal safety standards on the pipelines with a working relationship between the two:
        - This particular relationship will focus on underground storage regulations.
        - This is a second stage of improving the regulations since the 1990s.
        - Relationships need to be established – companies have worked together to form the standards themselves and realized they needed a regulatory standard to uphold these private sector-formed standards.

- Intrastate v interstate – PHMSA/federal regulation is the floor for the states and federal regulations; states then have the opportunity to add additional regulations based on needs per state:
  - Regulation for underground storage will be similar to this – same working relationship between federal and state governments.
  - Well permitting – it will be in the regulation, though not covered at the moment.
- **Question:** So much can go into permitting – some of this will run into PHMSA authority; how far can states go within permitting as to not conflict with PHMSA?
  - Nothing is currently written down to regulate this at the moment.
  - PHMSA would first work with the states and other interested parties to address these questions, which they hope to address now.
  - When building pipelines, there are permitting processes that go into the whole process; a participant argued that what happened with other regulations, is that the federal regulation actually sets an initial bar and states build on the regulation.
- There is a desire by the states to maintain a role in permitting in which PHMSA is not involved (e.g. high residential areas).
- PHMSA believes they definitely have a role for interstate and are on a fast track to establish regulations:
  - Want the communication lines to remain open
  - Understand that there will be updates and further input received as time goes on, allowing for this in the language used.
- California is interested in well regulations challenges but the role they play is a grey area with the permit process:
  - Believes PHMSA should work with the states.
  - Currently working on its certification process to align with PHMSA.
- PHMSA will require states to adopt the new federal regulations (6106 agreement)
  - States do not need to add to the PHMSA regulations if they don't want to; the PHMSA rulemaking will create a baseline, at least for intrastate fields.
  - While states are in the process of combining their regulations with those of PHMSA, they can send violations to PHMSA to handle.
  - PHMSA understands that there are new players and there is a learning curve; will work with states accordingly to ensure this works smoothly.

- **Question:** What is the timeframe? How soon will states need to comply in adopting new regulations?
  - Interim rulemaking is scheduled to be out by the end of the calendar year, 2016
  - They will be setting the rest of the stage soon (e.g. grant funding process, etc.)
- None of the regulations should prevent state regulations from being enforced upfront.

- **Question:** When states adopt the federal code, will it be verbatim?
  - Yes, this would ensure consistency across the nation.
- **Question:** PUC is a certification entity in California. Under the new regulations, does PHMSA not want more than one certification entity? What will happen to entities like PUC?
  - PHMSA wants to be efficient in determining partners.
  - They are gearing up to have more state partners; if the governor of a state has given the authority to a partner, PHMSA will look to work with a state-approved partner to start.
- **Question:** What if an entity decides they do not want certification for intrastate management of wells and do not think their own rules need to be more stringent?
  - Federal regulators will inspect either way.
  - Entities will have to certify to participate fully:
    - Information on this is currently on the website but these changes in regulations are in the beginning stages; more information on the process is forthcoming.
    - PHMSA will reach out through IOGCC; they are for working with state partners on the pipeline side and will reach out to help with certification.
- **Question:** As far as intrastate terms, is specific technology spelled out? If this is the case, what processes are being put into place and what should companies do [to address any new technology used]?
  - PHMSA has a technology section to cover newly emerging technology; they also will handle on a case by case basis.
  - There is no real approval process but an entity will receive "no objection" from PHMSA.
  - There is currently no language in the statute addressing any specific emerging technology but open to discussion.
  - 1170 and 1171 (performance monitoring):
    - PHMSA is trying to do future proofing to allow for regulation of emerging technologies but feels 1170 and 1171 have this built in.
    - They are trying to get head start on this identifying of new technology.
- **Question:** New PHMSA rules – will there be effects on both existing and emerging underground facilities?
  - Yes, it is set up to incorporate API RP 1170 and 1171, and working to cover both existing and emerging facilities.
  - PHMSA expectation is that PHMSA will be kept apprised as to how entities will maintain maximum well pressure and well information; also kept updated on changes made to the wells.

  - API 1170 & 1171 required 4 years of development, drawing knowledge from key stakeholders and experience – as all get familiar, PHMSA will help assess and determine where everyone fits.
  - It is a growing process; firms should keep in touch with PHMSA
- Regarding double-barrier state requirements, specifically in well design – this will be hard to adopt given historical wells:
  - AK and CA are moving toward double-barriers.
  - It is true that of the 17-18K storage wells, many just have a single barrier but have operated safely.
  - Requirements of double-barriers should be upheld but we need to come to an agreement as to what constitutes a barrier and barrier envelope.
  - It is difficult looking at different standards between a well barrier (tubing sheet) and barrier envelope.
  - A participant mentioned his firm has an existing well and segments of a well that need work:
    - They are currently monitoring now.
    - They should look at decision matrices to handle the situation until there is a need to actually add a double barrier.
    - Refer to ISO 16530 – published part 1 & 2 in 2014.
  - Wells must have surface casing and injection strings.
    - Look at results if your firm has both.
    - Is there real time monitoring?
    - Breach of these alone does not mean problem necessarily.
  - Results really should be the focus.
  - Think about the level of acceptable risk and what the cost is to install safety features to maintain that risk level; Figure out if it does actually work, though it is difficult though to qualify risk.
  - API RP 1170 an API RP 1171 are great starting points but vague:
    - California aimed to be more prescriptive.
    - There is some flexibility.
    - A firm should test on a regular basis (included in California regulation).
  - The proposed regulation addresses what is in 1170 & 1171 – does mention to do risk assessment.
  - This is difficult with age, location, design, how installed, etc. - many factors to consider for existing grids.

  - Look at mechanical integrity tests and frequency of tests used – firms should conduct further tests and more often.
  - Look at all parameters there is no exact answer at this point.
  - Put all assessments together and decide on whether to put in double-barrier or not.
  - Pipelines are single barrier systems, but now moving to be managed with improved technologies.
  - Operators currently going through assessments so they can verify and decide level of prescriptive; difficult in engineering considering time, risk, and condition.
  - Companies have done their own self-regulation and there is a body of knowledge already in existence that can be applicable – need to collaborate.
  - There should be a community decision of what is acceptable (ALARP); do we have the information and how will agencies data collect and monitor?
  - What is acceptable should be set up within 5 years.
  - There is a need to figure out metrics to measure performance across the industry, which will help build community trust.
- **Question:** Pertaining to old wells without data – if information cannot be obtained and there little to no analysis of integrity, how will PHMSA assess if the firm submits a risk assessment plan?
  - PHMSA would have to see specifics in the risk assessment plan.
  - It may be time to abandon old well, however.
  - If the well is in middle of nowhere with no leakage, it may be ok.
- **Question:** Is there a process when it is not good enough?
  - California allows different ways to evaluate and justify, and will not pass in certain cases.
  - A high bar is set if there is no real data.
  - A firm can try to use statistical methods and make reasonable assumptions, allowing a data set to grow for a while continuing operations as long as practicable.
- **Question:** Are training and certification of storage operators part of PHMSA rulemaking?
  - Training will be part of 1170/1171 section 11.
  - Make sure to document everything.
  - There will be a joint training with state and PHMSA.

3.2.7 Session 7: Well Integrity Management and Technologies

This session continued on the theme from session 5 on Well Integrity Management and Technology. It included a presentation on surface leak detection technology, another on well drilling and remediation practices, another on comprehensive well integrity methods, and the

final presentation described a project to replace 18 vertical wells in a residential community with 3 horizontal wells in order to lower overall risk and increase public acceptance.

Surface leak detection was mentioned prior to this session by the EDF as one of the components of a well regulatory framework and by the State of California DOC/DOGGR as part of their requirements for operators in California under emergency rules. The presentation on leak detection introduced a stationary technology using an open path laser that could be used to continuously monitor for leaks. Questions concerning the technology are whether it has been testing in realistic field conditions with variable weather and if there is a distance limitation between reflector and receivers. The operator noted that weather conditions did not impact the results and that the technology has worked at a range up to the 660 ft tested to date.

The presentation on well drilling and remediation identified several techniques that are used to reconstruct and repair old wells such as top joint reconstruction, casing patches, recasing and stimulation. A presentation on well integrity evaluation defined well integrity as the absence of significant leakage both internally and externally. The Colony Horizontal Well Project conducted by Southern Star Central Gas Pipeline reduced the risk envelope of a storage field by replacing 18 vertical wells located in a residential neighborhood with three horizontal wells outside of the neighborhood. The project was conducted not because of well integrity issues, but because the risk of operating the vertical wells was deemed high and incompatible with the current land use. The operator decided that the need to operate heavy vehicles within the residential neighborhood and the location of the wellheads was a significant risk that could be mitigated by relocating the wells. The project was deemed a success as the three wells were able to meet the operators' deliverability requirements and replace the 18 existing wells.

Session 7-1, Field Test of a Stationary Leak Detector at a Natural Gas Storage Facility, F. Rongere, PG&E

Session 7-2, Well Drilling and Remediation Practices in Conventional Gas Storage Reservoirs, J. Bach, Dominion Transmission

Session 7-3, Application of Well Integrity Methods for Gas Storage Wells, D. Arthur, ALL Consulting

Session 7-4, Colony Horizontal Well Project, T. Meyer, Southern Star Central Gas Pipeline

3.2.8 Session 8: Discussion Session on Downhole Safety Valves

This session provided opportunity for a deep dive into downhole safety valve (DHSV) technology. It should be noted that there is no standardized nomenclature for subsurface safety valves. Acronyms in use refer to different types of valves and have created considerable confusion. For instance, the acronym SSV is often used to refer to sliding sleeve valves, which are not the same as SSSVs, more commonly referred to as subsurface safety valves. Another acronym that is often used is SCSSV, or surface controlled subsurface safety valve. This report uses the term DHSV to refer to any valve placed below the wellhead that is installed with the purpose of responding to an off-normal condition. Standard sliding sleeve safety valves are not DHSVs in that they are typically operated by a wireline intervention and not installed as a means to mitigate a well failure.

After a presentation by a maker of downhole safety valves and a presentation by an operator, an open discussion on experience with downhole safety valves was held. It was noted that there are

only four manufacturers of DHSVs, and any operator may easily engage the manufacturers to learn about the technology. Both the manufacturer and an operator of downhole safety valves noted that proper maintenance could prolong the expected life of a DHSV. One operator noted that their field currently has 89 DHSVs and that 29 of those need replacement.

Session 8-1, Subsurface Safety Valves, M. Garrett, Baker Hughes

Session 8-2, Kinder Morgan's Experience with Downhole Safety Valves, A. Johnson, Kinder Morgan

Open Discussion of Operators Experience with DHSV; Jacob Abraham, Larry Kennedy, Anders Johnson, Marcus Garrett

Discussion Notes: The following comments were made during the discussion session:

- On DHSVs:
  - There is a love/hate relationship with them. It goes back to risk management and assessment. Step back to see where wells are located and what the risk is associated with them – make the decision based on that.
  - There has to be a period of time to bring this risk mitigation tool but what is that period of time? This must be determined. These next few years could leave us without supply (30–40% reduction when installing certain pieces).
  - It has been their experience to have a methodical review of where wells are placed and understand it is not a catchall for avoiding blowout – but we should identify where DHSVs could be actually effective.
  - Currently, there is tubing in wells with safety devices that are minimally intrusive and most effective for each well.
  - European perspective (on behalf of Germany): obliged to equip existing wells with safety valves. Surface controls are required in certain German states and not in others. Looking back in the past, they have not dealt with any issues with subsurface safety valves in the last two decades. Most issues are caused by the unintentional blocking of production from a closed valve.
  - **Question:** Do you know what reliability rates in Germany are for how often the valve has to be repaired or any maintenance performed?
    - Wells have to be tested two times a year by closing valves and testing rates.
  - Intervention incidences – most times, the problem we have with the wells is with interventions with the wells; risk assessment performed on what the risk was with and without DHSVs – there was an increase in risk from a societal standpoint with having the valves due to increased required maintenance.
  - Application for SSSV was originally for offshore regulations. If there is any type of breach should the flapper fail, the SSSV will not prevent gas from getting through the casing. For example, if one places the valve only 50 ft below the surface casing and the well string extends 3,000 ft, below the valve, it doesn't significantly reduce risk as well.

- One has to replace DHSV every 9 years and be prepared for next steps – start working with the manufacturer to see if reliability can be improved.
- Reliability is always something that comes up with regards to safety valves:
  - With gas storage, one would expect the valves to be more reliable in storage than in oil and gas environments
  - It is difficult to determine reliability of valves in terms of years.
- If one just uses a 5-year time period, talk about 20% of storage being out of service – there is a significant reduction the maximum daily withdrawal capacity. This is a huge reliability concern that needs to be taken into account in terms of regulations.
- New valves have a much lower failure rate than the one displayed in the previous presentation.
- One thing that is becoming clear after presentation:
  - There are going to be places where there is a need for safety valves, but there are places where one can mitigate risk without safety valves. The suggestion is that where one has instances where a safety valve is needed, sit with one of the four competent safety valve producers – listen to a variety of options and select the best equipment given your requirement for safety valves.
  - With time and work, they will also be able to manufacture ideas you currently may have only in your mind.

3.2.9 Session 9: Wrap-up Discussion

Description: During the opening of the meeting, we asked people to take notes on key unresolved points, questions, or area of concern. This final session was dedicated to addressing those questions and getting people's opinions on how to resolve these issues and the path forward in light of other ongoing Well Integrity efforts.

Panel discussion leaders: Steve Bauer, Grant Bromhal, Barry Freifeld, Scott Perfect, Kenneth Lee

Discussion Notes: The following comments were made during the discussion session:

- **Question:** Comment on board: "Why are we here? CA should simply admit its regulations were inadequate and bring them up to an acceptable standard. SoCal should simply admit that it was operating irresponsibly and change its practices. There is no need for multiple research labs, federal agencies, operators, consultants, and regulators to convene (much less spend thousands of hours) studying this – other than as a cautionary tale."
  - The SoCalGas representative admitted that regulations were inadequate and noted that California is working on bringing them up to a higher standard.
  - Regulators are asking for assistance in determining the best way to raise standards.
  - SoCalGas knew they needed to improve their risk mitigation plan – PUC didn't work quickly to support this. They should be working together.

  - When they looked at the problems, they would look at wells across the country and note that many are not up to their own standards. The question is how do you take 17,000 wells and efficiently improve gas storage? How do we get to where we want to go? What is the least risk pathway?
  - Key stakeholders ought to convene and learn from every major incident/catastrophe – it is good to recommend practices across the whole industry. Most storage operators realize this could happen to them being in a risky industry.
  - Never waste a good crisis – that's what we are trying to do. Take advantage of this opportunity with good participation across the board today.
  - In seeing how old some of the wells are, it's good we've convened, that the community recognizes their existence, and that it is recognized that something should be done sooner than later. It bothers some a bit that some here have said that many 40-year-old wells show no signs of wear after the casings have been inspected and so they think they will be fine – not a good attitude. We ought to expect that even steel will go bad and test accordingly.
  - PHMSA is trying to write effective regulation and needs all stakeholders involved. They want this to be a fully transparent process. We all have the same goal in mind in the end – a safe industry. Now, we have increased public trust, and we all have different roles to play.
  - This is a very complex issue that requires a systemic approach. So many interactions are taking place – historically these interactions have not been as effective. These workshops and open conversations among stakeholders are vital. We need to interact properly.

- **Question:** The regulatory community needs to contemplate – how do you regulate wells drilled through a natural gas storage reservoir? What regulations are considered for gas storage wells drilled through other activities?
  - In Ohio, they already have statutes and regulations for how to drill through gas storage reservoirs – they have to isolate all around and have enough strings of casing. Each string must pass a test. It is more costly but can be done.
  - Alaska is the same but also requires wells to go through monitoring and testing as they are storage well reservoirs.
  - In Oklahoma, a prudent storage operator has right to observe completion of producing well.
  - In a counterargument to the 40-year-old well comment – many of these wells have a suite of logs throughout that 40-year period. One can make informed decision if you have 20 years or so of logs and facts to base decision on these.
  - In regards to the cost, we've had an interstate person who said they had to increase their integrity – consider who is paying for all this.
- **Question:** Was there any rate concern or rate recovery concern? They do not have ability to pass along the cost, and there is great concern that it's gotten right the first time. This could be taking dollars away from someone else if this is made a higher priority. The

whole purpose of ranking is that they have flat budgets; doing what they can to keep people safe.

- Not all are regulated rate-based however; some are market-based.

4. TASK 2. CIRCUMSTANCES SURROUNDING ALISO CANYON EVENT

The objective of this section is to share and assess the apparent causes of the Aliso event in order that the community can evaluate current and proposed safety measures to assure that these measures will help prevent similar events in the future. The information used to examine the Aliso Canyon event include publicly available logs and records of the Aliso Canyon Field, data transmitted from the DOC/DOGGR to the Aliso Canyon Lab Team, and ad hoc communications during site visits to Aliso Canyon while the event was ongoing. A more definitive post-mortem analysis is being conducted by the California Public Utilities Commission, which has retained the services of Blade Energy Company to perform a definitive root cause analysis, which will include additional assessments not available to the Lab Team at the time of writing this report. To that end, the currently identified items believed to have contributed to the Aliso event and assessed herein include, aging well and corrosion potential, production through casing (no secondary barrier) and its potential impact, absence/presence of safety valving, emergency response (top kill attempts/failures), and surface and subsurface monitoring and leak detection at the Aliso Canyon facility.

4.1 INTRODUCTION

The Aliso Canyon event began with a gas leak from well SS-25 beginning on or about October 23, 2015. Initially a temperature survey was attempted and a presumed hydrate plug in the tubing at the approximate depth of 467 ft prevented further logging. A coiled tubing unit was called out and a glycol wash was used to remove the plug. The presumed leak was located from temperature and noise logs at 400–500 ft in depth in the casing and the gas leaked down and around the shoe of the surface casing at near 1,000 ft depth. The leak became exacerbated by repeated (eight) top kill attempts over the course of the first 2 months of the event. A relief well, spudded in mid-November, was constructed and used to eventually kill the well. Relief well intercept occurred on February 12, 2016 and gas flow was stopped. The well was subsequently cemented and confirmed sealed on February 18, 2016. An overview timeline of the events at Aliso Canyon is provided in Figure 2.

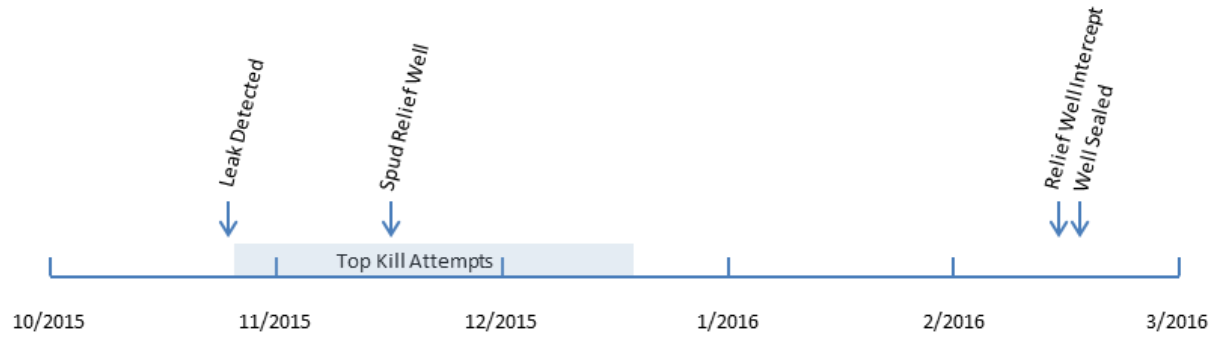

Figure 2: Timeline of Aliso Canyon Events.

As background, the Aliso Canyon Facility consists of 114 storage wells with spud age ranging from 1939 to 2014 (Figure 3). The field stored ~80–90 bcf, with maximum operating pressure of ~2,900 psi, and an average storage formation depth of 8,500 ft (7,200 to 10,000 ft).

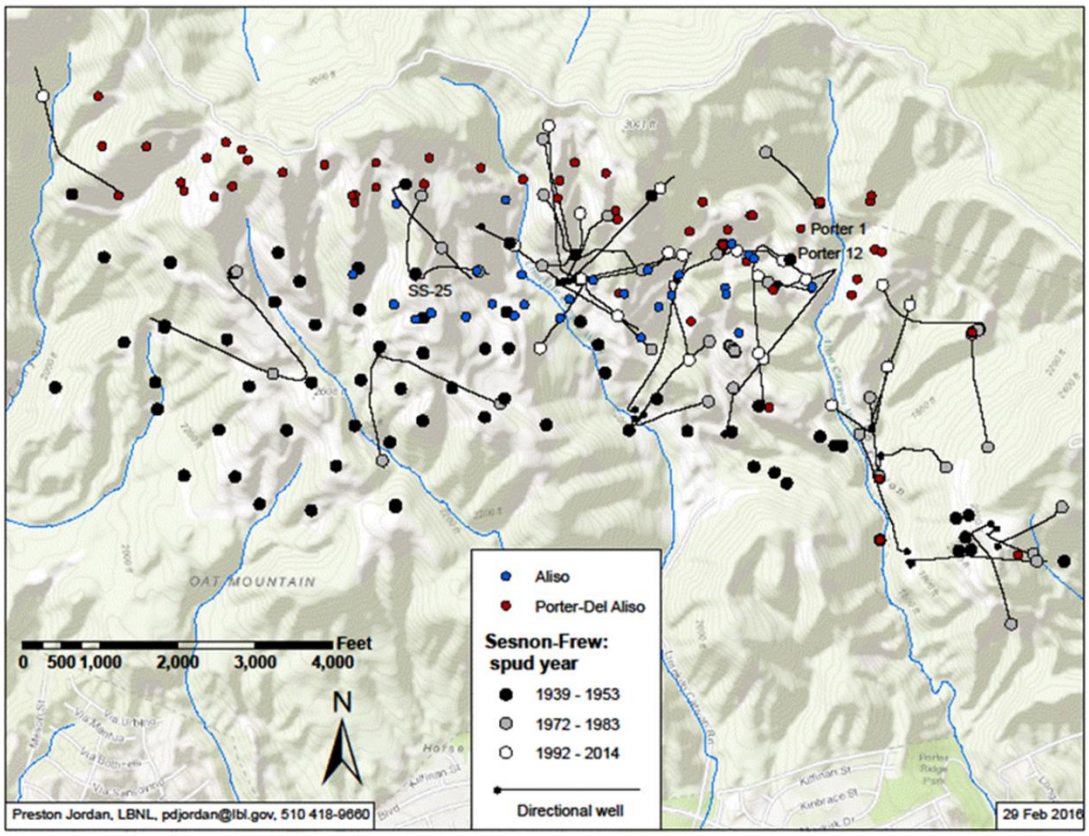

Figure 3: Layout and age distribution of Aliso Canyon storage wells.

The SS-25 well schematic is shown in Figure 4. The well was operated by injection and withdrawal through both tubing and casing, thus functioned for its life with a single barrier to the environment. The top of the storage interval at SS-25 is at about 8,500 ft. The leak was located as shown, based on temperature and noise logs run after the leak was observed at the surface. The well geometry details proved important to subsequent well kill analyses. This includes well volume, placement of a plug at 8,393 ft above a sliding sleeve valve and perforations above the plug (these later activities were completed as part of the mitigation work by SoCalGas).

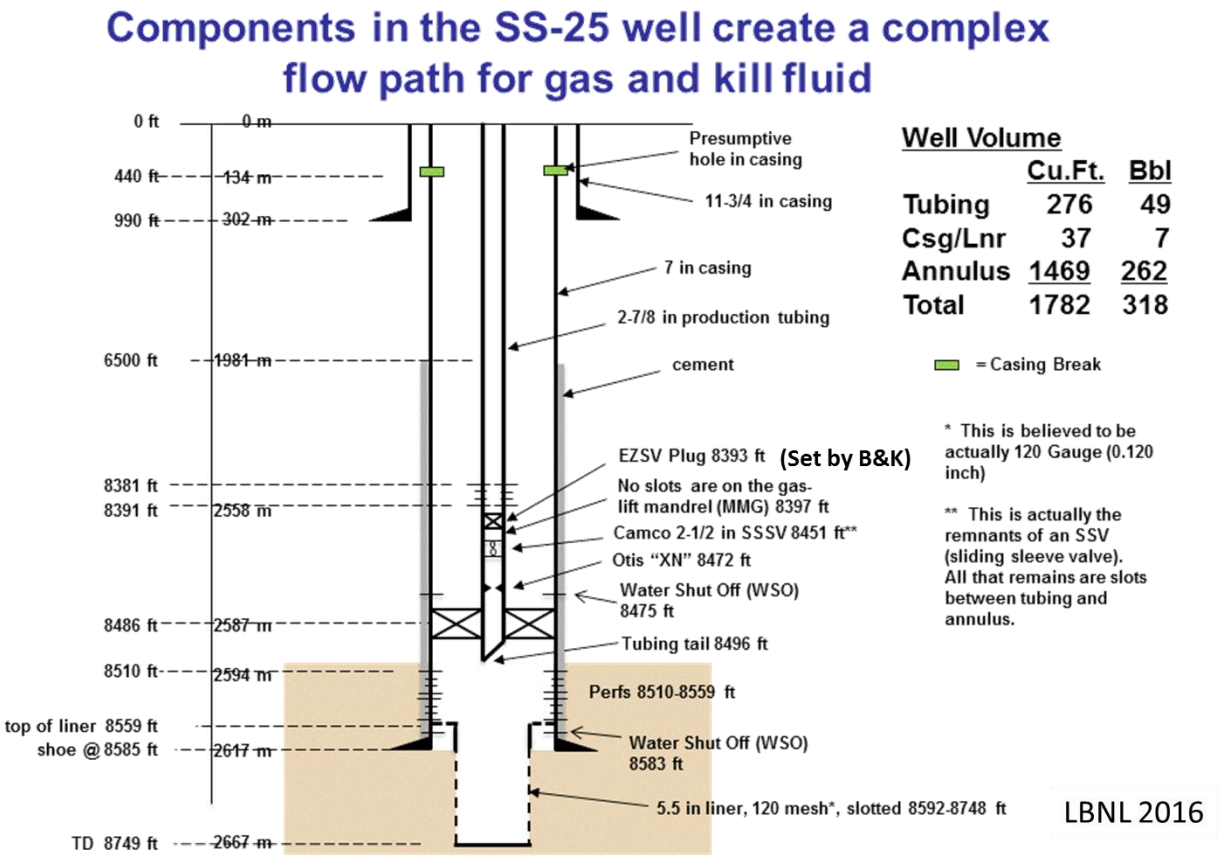

Figure 4: SS-25 well schematic.

4.2 STANDARD SESNON 25 WELL HISTORY

The information presented here has been extracted from the Standard Sesnon 25 well history file available from the California Department of Conservation Division of Oil, Gas, and Geothermal Resources (DOGGR).

Aliso Canyon Well Standard Sesnon 25 (API 037-00776) was originally designated as Standard Sesnon 25, then renamed to SS-25 in 1968, then, renamed back to Standard Sesnon 25 in 1991. This well was originally drilled as an oil and gas production well, and then later converted to a gas storage well. Drilling of the well started on October 1, 1953, and the well was completed in April of 1954. During drilling, the original borehole was abandoned due to an unrecoverable drill string and tool set that were lost in the hole. The main hole was sidetracked at a depth of approximately 3,900 ft, and then drilled to full completion depth of 8,749 ft. All depths given here are relative to the drilling platform derrick floor which was 6.35 ft above the ground surface. Ground surface elevation at the Standard Sesnon 25 well site is listed as 2,927 ft above sea level. The casing installed during the original completion of this well is listed in Table 1. It is important to note that the top-of-cement (TOC) for the production casing was at a recorded depth of ~6,500 ft—this situation ensured that a failure in the casing above the TOC at operating pressures recorded at the time would yield a high likelihood of a broached well. The well history

file does not indicate any formation stimulation was performed during the original well completion.

Table 1: Original installed casing for Standard Sesnon 25

Casing Depth (ft. bgs)		Casing Size I.D. (in.)	Casing Weight (ppf)	Casing Condition	Casing Grade
Start	End				
0	990	11.75	42	New	R-40
0	8,585	7	23, 26, 29	New	J-55, N-80
8,559	8,748	5.5	20	New	J-55

In May of 1973, a rework of Standard Sesnon 25 to convert it to a gas storage well was started. This involved the removal of the original production packer and tubing, cleaning of the well using a casing scraper, creation of additional casing perforations, and installation of a packer and production tubing system. In addition, the well cellar and casing head was also worked on, this included "unlanding" of the 7-in. casing. The original production tubing installation at this time included a sliding sleeve valve which was at this time left permanently configured in the open position. This provided a flow pathway between the production tubing and the casing. No subsurface safety valve was installed at this time.

In June of 1976, Standard Sesnon 25 was reworked. During this rework, the production tubing was removed and a mill bit was used to clean out the well to a depth of 8,359 ft. Then the production tubing was reinstalled with a sliding sleeve valve.

Although there is no written narrative of this in the well history file, well diagrams and tubing detail listings indicate that Standard Sesnon 25 was reworked again in February of 1979. A 1979 listing of the tubing details for this rework lists a Camco SC-1 Safety System as being included in the tubing string. However, a 1986 well construction diagram does not show this safety system and the diagram annotation lists "Replaced safety system" as part of the effort in this rework. This is the last rework listed for this well in the well history file prior to identification of the leak at Standard Sesnon 25 in October of 2015. Figure 5 below shows a timeline of the major events of the Standard Sesnon 25 well.

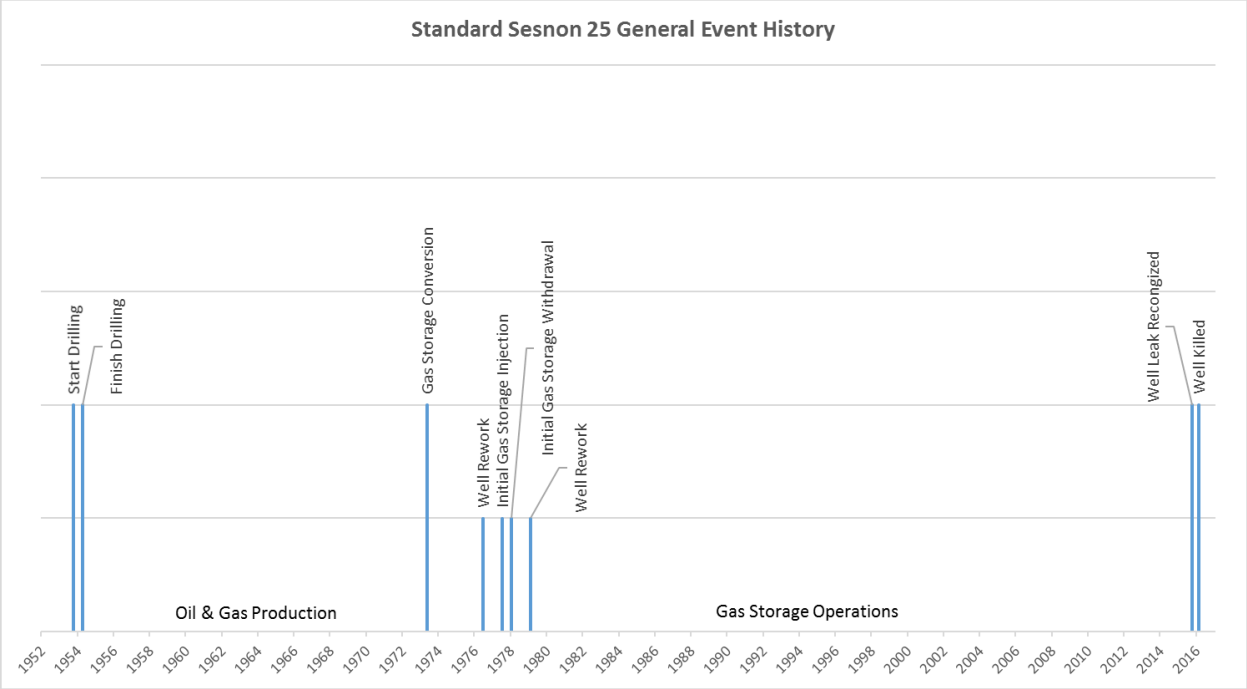

Figure 5: Timeline of major events for Standard Sesnon 25 well.

4.3 GENERAL OPERATIONAL HISTORY OF STANDARD SESNON 25

The following description of the operational history of Standard Sesnon 25 relies on the information available from online data from the DOGGR.

Based on the available information obtained from the well history file, it appears that the Standard Sesnon 25 well was configured for gas injection/withdrawal via the cemented casing since its conversion to a gas storage well in 1973. As noted in the well records, Standard Sesnon 25 was configured with a subsurface sliding sleeve valve (SSSV) above the isolation packer. A valve of this type allows for gas flow between the tubing and the surrounding casing annular space, and therefore provides a mechanism for gas transport via the casing. Although this configuration provides the potential for gas transport via the casing, if the valve is closed, then the tubing is effectively not in flow communication with the casing annular space. The well history narrative from the 1973 well rework lists the SSSV as being configured in the open position.

Although there is no information regarding tubing versus casing production volumes in the available information from the California Department of Conservation, casing and tubing pressures were recorded. Figure 6 below shows the tubing and casing pressure history curves during gas withdrawals starting from 1980 in segments of 20-year length. For a vast majority of the pressure history curves, the two curves overlie one-another. This is especially true since 2002. This indicates that the casing annular space was in communication with the tubing interior and the gas storage horizon. This can also be seen in Figure 7 which is a scatter plot of casing versus tubing pressures for entries where there was a non-zero reading for either the tubing or casing pressure. As shown in this figure, a large percentage of the pressure values fall on the X=Y diagonal of the plot indicating the pressures are equal. In fact, numerical comparison of

these tubing and casing pressure data show that 85% of the casing pressure values are within 5% of the tubing values. It is not completely certain why the casing and tubing pressures are not always approximately equal but the data clearly indicates the tubing and casing were in connection since well conversion.

Figure 6: Casing and tubing production pressure history curves for Standard Sesnon 25.

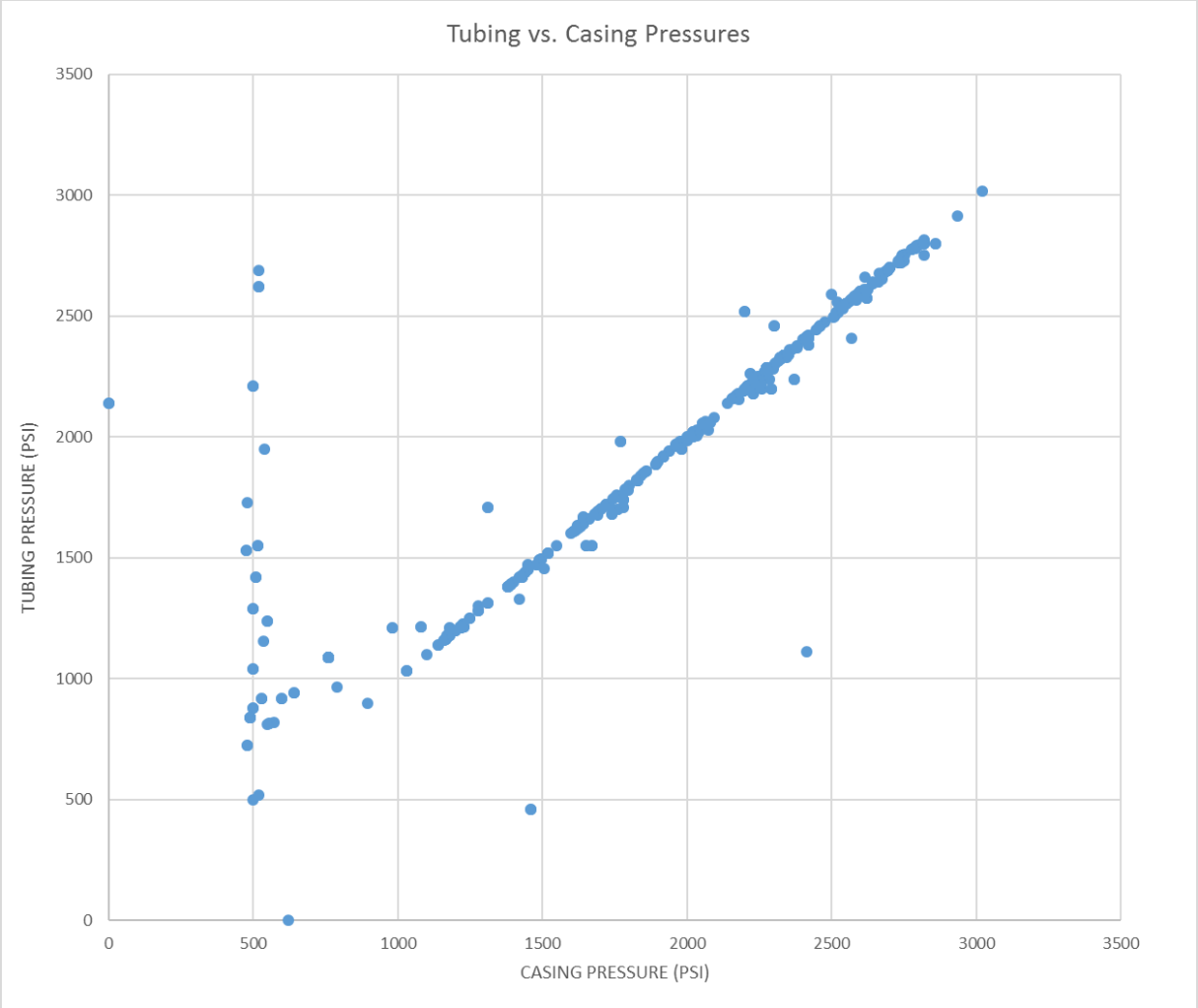

Figure 7: Scatter plot of casing versus tubing pressures.

Surface injection pressures for Standard Sesnon 25 are shown in Figure 8. The seasonal, cyclic nature of this gas storage field is clearly evident in the pressure history curve. In addition, this figure shows there is a large data gap where no pressure history was available in early to mid-2000.

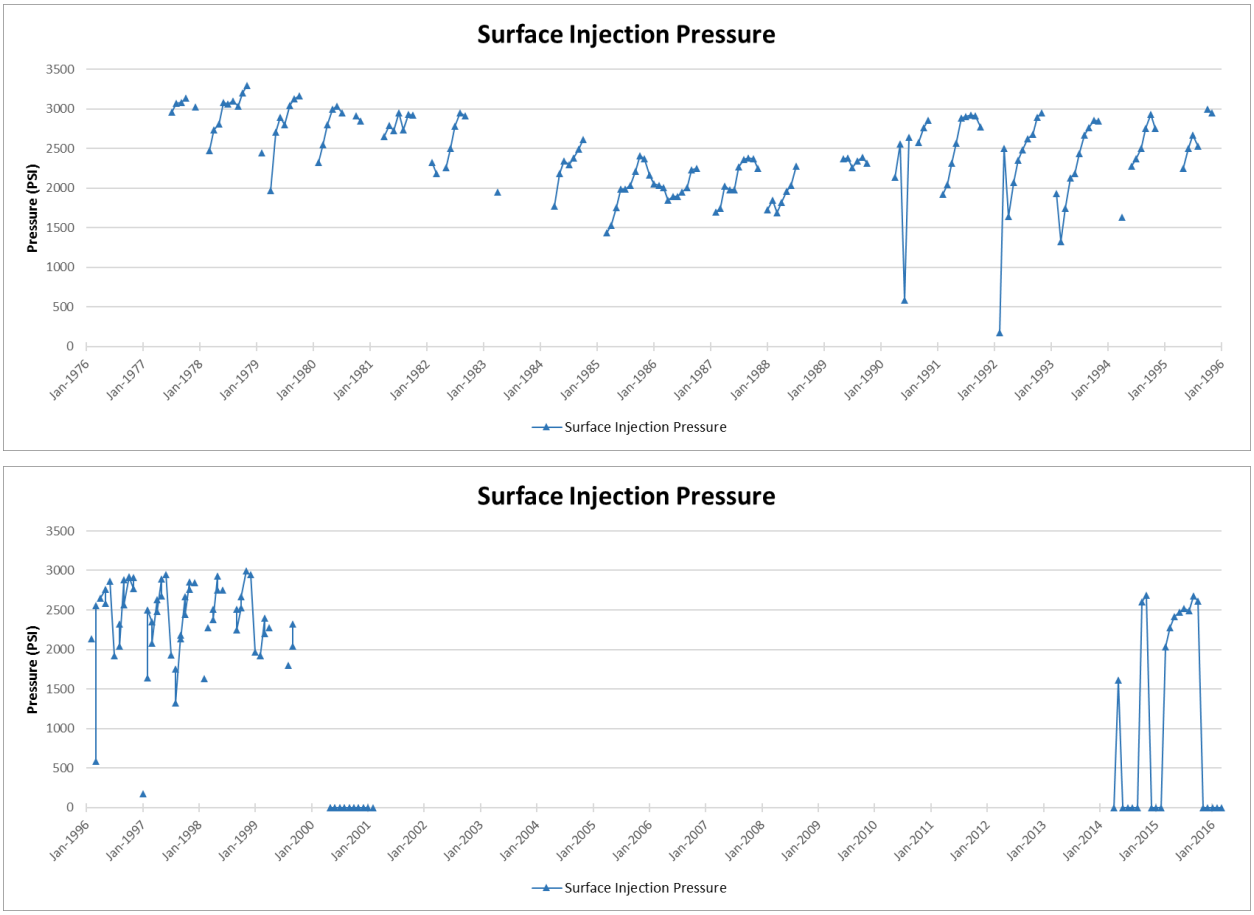

Figure 8: Surface injection pressures for Standard Sesnon 25.

4.4 STANDARD SESNON 25 WELL LOGGING

During its history as a gas storage well, Standard Sesnon 25 was monitored for leakage using downhole well log measurements. These consisted primarily of temperature, noise, and pressure logs. Table 2 lists the logs available from the California Department of Conservation Division of Oil, Gas, and Geothermal Resources online resources for the time Standard Sesnon 25 was being used for gas storage; two earlier well logs related to the original completion of this well are also available. A timeline of this well log information is also provided in Figure 9.

It should be noted that the logging in the past was exclusively performed to detect the presence of a leak in Standard Sesnon 25. Since 1979 (the last presumed time the tubing was pulled), there are no records of logs performed for the purpose of evaluating the condition of the casing that could be used to assess *a priori* risk of a leak. For example, no logs were located that provide an evaluation of metal loss in the production casing; the primary barrier to the surrounding environment.

Table 2: Standard Sesnon 25 Well Log History (after conversion to gas storage through 2015)

Well Log Type	Date
Temperature	November 7, 1991
Noise	November 7, 1991
Temperature	September 16, 1993
Temperature	September 21, 1994
Temperature	November 5, 1997
Temperature	November 6, 1998
Temperature	August 7, 2001
Temperature	July 27, 2004
Temperature	August 10, 2005
Pressure	August 10, 2005
Temperature	July 25, 2006
Pressure	July 25, 2006
Temperature	October 5, 2009
Temperature	December 14, 2010
Temperature	September 12, 2011
Temperature	May 29, 2012
Noise	June 1, 2012
Temperature	October 2, 2013
Temperature	October 21, 2014
Pressure	November 8, 2015
Temperature	November 8, 2015
Completion Profile	November 8, 2015
Temperature	November 9, 2015
Noise	November 9, 2015
Temperature	November 19, 2015
Noise	November 19, 2015
Temperature	November 30, 2015
Noise	November 30, 2015

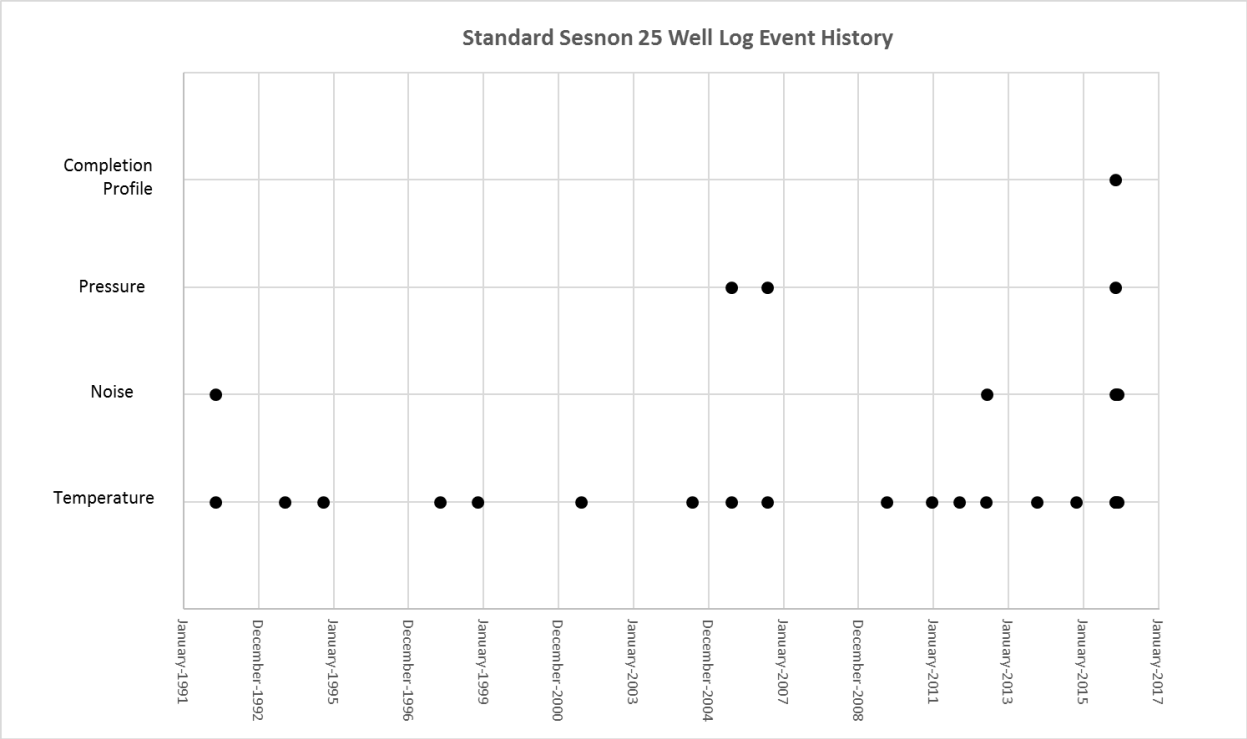

Figure 9: Timeline of well logging activities for Standard Sesnon 25 during gas storage.

4.5 SUMMARY OF SUBSURFACE SAFETY VALVE USE AT ALISO CANYON GAS STORAGE FACILITY

The DOGGR online resources lists 186 wells within the Aliso Canyon oil and gas field. This includes wells currently producing from horizons other than the gas storage strata, plugged and abandoned wells, and planned but not drilled wells. The DOGGR online resources lists 114 wells as being part of the Aliso Canyon gas storage facility.

The following discussion and statistics regarding the Aliso Canyon gas storage facility wells is based on information obtained by reviewing the DOGGR well history files. The completeness and reliability of this discussion is directly dependent on the completeness and reliability of the well history files.

Subsurface safety valves are commonly used in the off-shore environment and are devices designed to shut-off flow to the surface. These are different systems than the aforementioned subsurface sliding sleeve valves, which provide a connection between the tubing and casing. In general, it appears as though downhole safety valves (DHSVs) were installed in many of the original wells when the field was converted to a gas storage facility in the 1970s. Many of these DHSVs were then removed and not replaced during later well workover operations. Wells drilled since ~1980 have not had any DHSV installed at any time. Table 3 shows a summary of the use of DHSV's and packer and tubing well completions for the Aliso Canyon gas storage facility based on review of the well history files. Wells were considered as being capable of casing production if the tubing was configured for gas flow to the casing, or if there was no production tubing.

Table 3: Summary of Aliso Canyon Gas Storage Facility Well Configurations

Parameter	Well Count
Total number of wells	114
Wells with SSV at some point in their history	54
Wells with no indication of SSV installation	60
Wells using packer and tubing production	102
Wells configured for casing production (includes wells with subsurface sliding sleeve valves)	80

Table 4: API Numbers for SoCal Gas Aliso Canyon Gas Storage Wells

(Note: API numbers are hyperlinked to the online data from the California Department of Conservation Division of Oil, Gas, and Geothermal Resources.)

Well Name	Well API Number
Standard Sesnon 10	03700040
Standard Sesnon 29	03700041
Ward 3	03700192
Sesnon Fee 1	03700647
Sesnon Fee 2	03700648
Sesnon Fee 3	03700649
Sesnon Fee 4	03700650
Sesnon Fee 5	03700651
Sesnon Fee 6	03700652
Sesnon Fee 7	03700653
Sesnon Fee 8	03700654
Frew 2	03700665
Frew 4	03700667
Frew 5	03700668
Frew 6	03700669
Frew 7	03700670
Frew 8	03700671
Fernando Fee 32	03700686

Table 4: API Numbers for Aliso Canyon Gas Storage Wells (cont.)

Well Name	Well API Number
Fernando Fee 33	03700687
Mission Adrian 3	03700693
Porter 12	03700701
Porter 25R	03700712
Porter 26	03700713
Porter 30	03700717
Porter 32	03700719
Porter 34	03700721
Porter 35	03700722
Porter 36	03700723
Porter 37	03700724
Porter 38	03700725
Porter 39	03700726
Porter 40	03700727
Porter 44	03700731
Porter 45	03700732
Porter 46	03700733
Porter 47	03700734
Porter Sesnon 42	03700753
Standard Sesnon 02	03700755
Standard Sesnon 03H	03700756
Standard Sesnon 04	03700757
Standard Sesnon 05	03700758
Standard Sesnon 06	03700759
Standard Sesnon 09	03700762
Standard Sesnon 11	03700763
Standard Sesnon 12	03700764
Standard Sesnon 13	03700765
Standard Sesnon 14	03700766
Standard Sesnon 16	03700768
Standard Sesnon 17	03700769
Standard Sesnon 24	03700775

Table 4: API Numbers for Aliso Canyon Gas Storage Wells (cont.)

Well Name	Well API Number
Standard Sesnon 25	03700776
Standard Sesnon 30	03700780
Standard Sesnon 31	03700781
Porter 32B	03721276
Porter 32A	03721277
Fernando Fee 35E	03721278
Fernando Fee 35C	03721279
Fernando Fee 32F	03721313
Porter 26E	03721319
Porter 26D	03721320
Fernando Fee 32E	03721321
Standard Sesnon 25A	03721322
Standard Sesnon 25B	03721323
Porter 26C	03721353
Porter 32F	03721354
Porter 32D	03721355
Fernando Fee 32D	03721356
Porter 26B	03721357
Fernando Fee 32B	03721358
Fernando Fee 32C	03721359
Porter 32C	03721360
Standard Sesnon 44B	03721361
Porter 26A	03721362
Porter 32E	03721363
Standard Sesnon 04A	03721375
Fernando Fee 35D	03721453
Standard Sesnon 44A	03721455
Fernando Fee 35A	03721457
Fernando Fee 35B	03721458
Fernando Fee 32A	03721872
Porter 42A	03721876
Porter 42B	03721877

Table 4: API Numbers for Aliso Canyon Gas Storage Wells (cont.)

Well Name	Well API Number
Porter 42C	03721878
Mission Adrian 1A	03721891
Mission Adrian 1B	03721892
Fernando Fee 34A	03722044
Porter 37A	03722046
Porter 69A	03722051
Standard Sesnon 04-O	03722063
Fernando Fee 34BR	03722302
Ward 3A	03722306
Porter 68A	03722742
Porter 69B	03724127
Porter 69C	03724128
Porter 69D	03724130
Porter 68B	03724136
Porter 69E	03724138
Porter 24A	03724143
Porter 24B	03724144
Porter 72A	03724145
Porter 72B	03724146
Porter 69H	03724223
Porter 69J	03724224
Porter 69G	03724225
Porter 69F	03724226
Fernando Fee 38A	03724230
Fernando Fee 38B	03724231
Fernando Fee 38C	03724232
Porter 69K	03724236
Porter 50B	03724336
Porter 50C	03724337
Fernando Fee 32G	03730374
Fernando Fee 32H	03730456
Standard Sesnon 04B	03730460

4.6 EMERGENCY RESPONSE (TOP KILL ATTEMPTS)

In response to the leak, SoCalGas and their contractors attempted to stop it using a method known as a top kill. In this method dense fluids are pumped from the surface through the tubing into the well and against the upward flowing gas to cease its flow. During the time from when the leak was recognized at the surface on October 23, 2015, top kill attempts were made on 10/24/2015, 11/6/2015, 11/13/2015, 11/15/2015, 11/18/2015, 11/24/2015, 11/25/2015, and 12/22/2015. Heavy barite mud and calcium chloride solutions were systematically pumped with lost circulation materials, ball sealers, steel balls, golf balls, woody plugging agents, and junk. Over time the successive attempts were forcibly rejected by the upward flowing gas and further eroded the gas vent opening(s) from the initially reported vent dimensions of pencil width thin cracks several feet long.

Successive top kill attempts caused erosion and expansion of the vent; the vent eroded to include the wellhead (Figure 10). During the later top kill attempts, the wellhead experienced severe vibrations. In an effort to protect the wellhead it was secured with strapping (which failed during a kill attempt). The wellhead was eventually secured with a bridge structure shown in Figure 10. The final vent reached a dimension ~40 ft by ~60 ft be more than 20 ft deep with an estimated gas flow rate of 25 to 60 MMcfd.

Figure 10: Vent crater caused by expulsion of top kill attempt materials.

All of the top kills failed. LBNL simulated the top kills as prescribed from SoCalGas information using a drift-flux flow model. The model calculations confirmed the failures; as performed, they should not have killed the well. The modeling illustrated that the high gas flow rates and the geometry of the lower section of the well severely inhibited the ability of the top kill attempts from being effective. During the top kill attempts, fluids pumped down the tubing had to exit the perforations above the plug set during the intervention operation and then re-enter the tubing through the original valve at 8,451 ft in order to enter the gas producing area of the well. The gas flowing up the well was able to entrain the kill fluids exiting the tubing and gas flowing out the tubing inhibited the kill fluids from re-entering the tubing. Exacerbating this issue were kill operation limitations caused by the structural concerns for the wellhead. This is shown schematically in Figure 11 where the kill fluid (brown) has to build up in the casing and overcome the methane gas (blue) flowing out of the SSV slots. In the lower section of the cased

interval, gas and liquid are mixed, the density becomes sufficiently small, and the upward velocity of the escaping methane is sufficiently great to force the liquid/gas mixture up the well and out the leak.

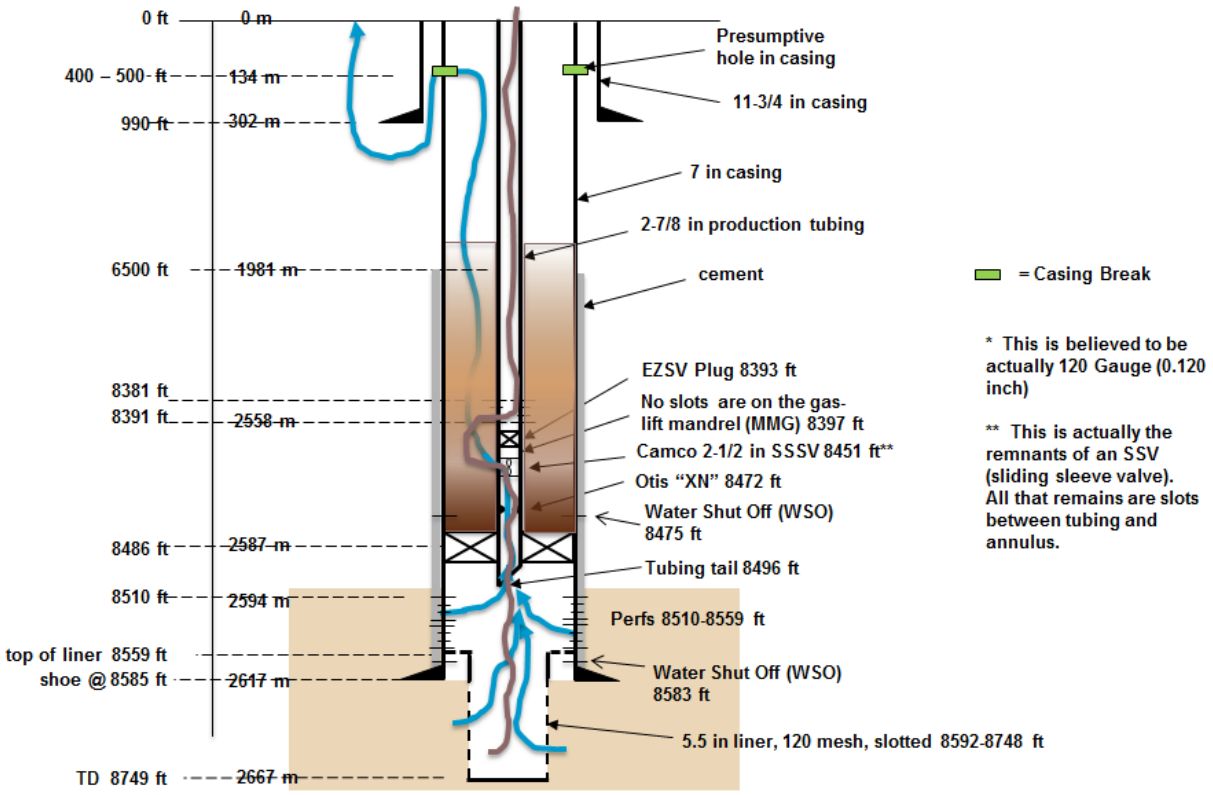

Figure 11: SS-25 top kill failure scenario.

4.7 MONITORING AND LEAK DETECTION (AT SURFACE AND/OR BELOW GROUND)

The storage industry, to a great extent, has relied on subsurface measurements to detect subsurface leaks. Commonplace for the industry are noise logs to listen for noise irregularities (perhaps indicative of a leak) and temperature logs, looking for thermal anomalies indicative of subsurface flow; for both of these technologies historical records are of great value for comparative purposes.

We reviewed the current CA state records for noise and temperature surveys and additional geophysical tools that have been run in the Aliso Canyon storage wells and the data source may be found in the hyperlinked Table 4 in Section 3. These logs are summarized below and portrayed in Figure 12. Early logging of wells (in the 1950s) were primarily for formation characterization, for example electrical logs; formation characterization records exist for only about half the wells. In the 1970s, as part of the conversion to storage, only a small fraction (about ¼) of the wells were logged; these focused on cement bond and neutron logs. In recent

time there has been much more well logging (e.g., noise and temperature logs), however the vast majority of the wells remained unevaluated for casing as cement integrity before the 2015 leak event.

- All wells have been or are being surveyed for noise and temperature in the past year-from during the leak time frame and since the leak incident
- In the 5 years prior (2015–2010), most wells were surveyed annually for temperature
- In the next 5 prior years (2010–2006), most wells were surveyed every other year
- For the time frame 2005–1990, most wells were surveyed at time intervals greater than every other year
- For the time frame from 1990 to the conversion date (1970s), surveying was sporadic
- There are infrequent additional geophysical log data for the storage wells that could possibly have been used to assess well integrity, but nothing recent nor systematic.

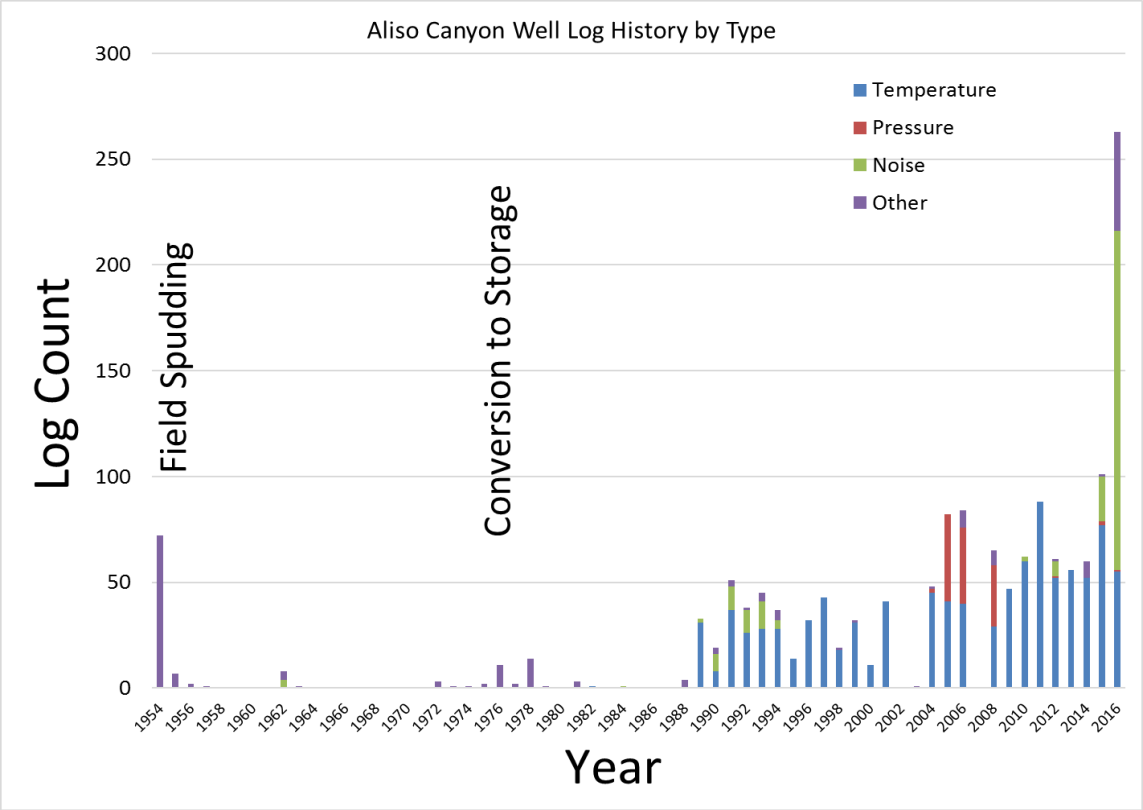

Figure 12: Aliso Canyon Well Logging Timeline.

4.8 SUMMARY AND CONCLUSIONS

A formal root cause analysis of the leak at SS 25 has been initiated by the California Public Utilities Commission through a third party contractor. This root cause analysis includes detailed work at the leak site and it is not known when this analysis will be completed. While the authors of this report are not part of this investigation, publicly available information (State of CA-DOGGR, 2016) allows for several observations. SS-25 was constructed through ordinary

circumstances consistent with the rest of the Aliso Canyon field; it began as a production well and then was converted to use in natural gas storage. The data indicates the Standard Sesnon 25 well was operated in natural gas storage pressure cycling through both casing (uncemented in the uppermost critical sections) and tubing, providing only a single barrier; this was common practice at the storage field. The SS-25 well was monitored for gas leaks in a similar manner to other wells at the field, annually in recent time, bi-annually in less recent time, and ranging to sporadic monitoring in historic time. Logs to assess the risk of the well system (e.g., metal loss in the casing) were not located.

The top kill attempts all failed; subsequent analyses indicate that the attempts failed because the subsurface flow paths were complex and impeded the delivery of kill fluids as required to suppress gas flow.

The practices for monitoring and assessing leaks (temperature and noise) and leak potential (cement bond, metal thickness, and pressure testing) for the Aliso Canyon facility were inadequate. Analyses of top kill scenarios used in advance of a kill attempt could perhaps be used to assess the potential success of a kill. Poorly executed top kills can have a detrimental effect on the well condition and future kill attempts.

5. TASK 3. REGULATORY REVIEW AND THE POTENTIAL FOR PROBLEMS AT OTHER STORAGE SITES

5.1 INTRODUCTION

The incident at the Aliso Canyon storage field has brought the issues of aging natural gas infrastructure and inadequate monitoring practices for natural gas storage field wells to the public's attention. The question remains, how many other wells in natural gas storage fields could fail and cause similar events with serious climate implications or even loss of life. There are more than 400 natural gas storage facilities in the United States, located in over 30 different states (EIA, 2016a). They include wells that range in age from less than 5 years to over 125 years old. Well completion technology has changed significantly over that time period, with many fields in similar condition to the one at Aliso Canyon. The complexity of natural gas storage facility regulations further complicates matters. Because of the involvement of federal and state agencies and the uncertainty around which has jurisdiction over what sites—and which aspects of each site—it can be difficult to get a clear picture of not only the state of natural gas storage wells, but also the rules by which they are managed.

The following sections include a description of the issues related to regulating natural gas storage facilities; how the regulations vary from state to state; and how they have changed over time, including the description of a few incidents that have spurred increased regulatory scrutiny. The chapter ends with an analysis of the data that is available on natural gas storage wells across the country, including the ages of active and plugged wells, well depths, and the proximity of gas storage fields to population centers.

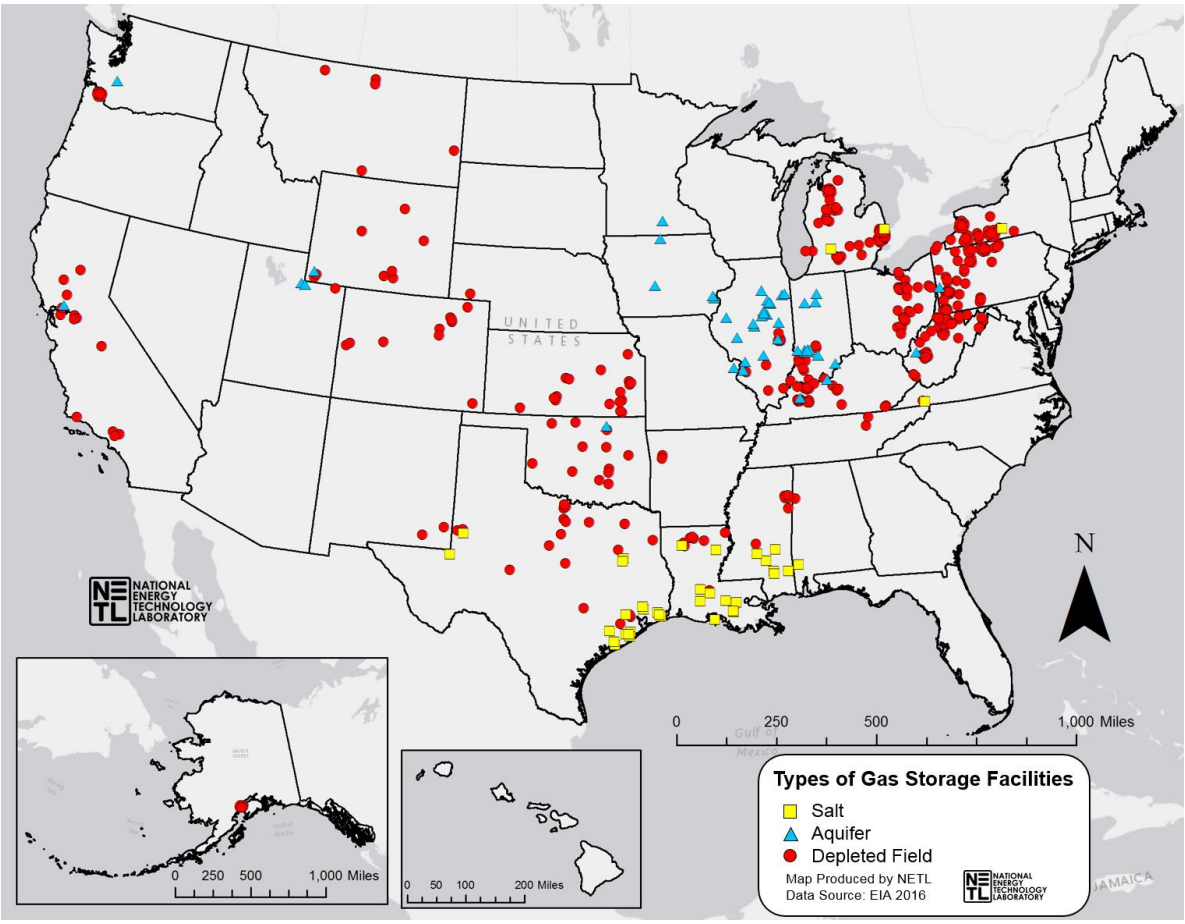

Figure 13: Types and count of gas storage facilities in the United States (U.S. EIA, 2016b).

5.2 REGULATION OF NATURAL GAS STORAGE FACILITIES

Overview of Jurisdiction to Regulate Natural Gas Storage Facilities

Just as natural gas storage and transmission is critical for ensuring reliability of domestic energy supplies, appropriate regulations are critical for ensuring the safety of such systems. Regulation of interstate natural gas pipelines servicing UGS facilities falls under federal jurisdiction under the Natural Gas Pipeline Safety Act (NGPSA), codified at 49 U.S.C. § 60101, et seq and Natural Gas Act (NGA) 15 U.S.C. § 717f(c) et seq, The Pipeline Hazardous Materials Safety Administration (PHMSA) has been regulating interstate pipelines for decades. However, regulatory authority of natural gas storage facilities—including geologic as well as engineered media such as wells and related infrastructure—is less well established. PHMSA has recently notified the public of its intent to exercise its federal rulemaking authority in the domain of UGS facilities from the wellhead and extending downhole, later this year. Several states have issued and enforced rules related to such facilities (State Corporation Commission of the State of Kansas, 2015; Texas Administrative Code, 2012), however there is substantial uncertainty regarding the validity or enforceability of some state regulations (Wright, 2010).

Interstate versus Intrastate Regulation

Regulatory authority for permitting and inspection of wells and facilities receiving or storing gas currently differs for interstate and intrastate gas storage infrastructure. For purposes of the NGA and NGPSA, intrastate pipelines operate exclusively within the borders of a single state, and link local markets to natural gas producers within that state. These pipelines do not fall within the jurisdiction of the Federal Energy Regulatory Commission (FERC) or PHMSA states' public utilities commissions and State oil and gas boards currently establish their own regulatory frameworks for these intrastate facilities. However, pipelines which link multiple states are considered to be "interstate" pipelines, and fall under federal regulatory jurisdiction. Interstate pipelines are subject to the permitting authority of the Federal Energy Regulatory Commission (FERC). Approximately half of the Nation's 415 UGS facilities are interstate facilities, and half are intrastate facilities.

Past Challenges to State Jurisdiction to Regulate Natural Gas Storage Facilities

Understanding past jurisdictional limits on state regulatory oversight and how those uncertainties have been addressed can inform the development of future regulations aimed at improving natural gas storage safety. A 2010 challenge to state regulation over natural gas storage facilities in Kansas provides insight into potential limitations on state rulemaking and enforcement. In 2001, the Kansas Legislature vested jurisdiction for the safety of underground porosity and salt storage of natural gas in Kansas in the Kansas Corporation Commission and Kansas Department of Health and Environment, respectively. This regulatory action occurred following a 2001 natural gas storage leakage incident in Hutchinson, Kansas that caused two fatalities. A series of Kansas state regulations were adopted and codified in the following years.

Colorado Interstate Gas Company (CIG) subsequently sued the State of Kansas to prevent enforcement of the rules on the basis that federal law (the NGA and NGPSA) pre-empted the Kansas State law. CIG argued that the Federal Energy Regulatory Commission (FERC) possessed exclusive jurisdiction over both natural gas storage economic and safety regulation. The Kansas District Court agreed with CIG and ruled that FERC and PHMSA have exclusive authority to regulate the safety of interstate natural gas facilities, and the state is precluded from claiming any authority to establish and enforce its own safety standards, whether supplemental or not. The CIG ruling was based on the court's reasoning that underground natural gas storage reservoirs are "pipeline facilities" within the meaning of the NGA. The United State Supreme Court reached a similar conclusion, ruling that storage of gas in interstate commerce falls within the scope of "transportation," for purposes of the NGA (U.S. Supreme Court, 1998).

By way of contrast, in a separate 2011 case, Petco Petroleum v Natural Gas Pipeline Company of America (United States District Court, S.D. Illinois, 2011), a federal district court held that underground natural gas storage facilities are not pipelines within the meaning of the NGA, and denied federal jurisdiction for a citizen lawsuit arising out of an underground gas storage facility incident.

As a result of the Aliso Canyon incident, in 2016 PHMSA issued an advisory bulletin regarding safe operations of underground storage facilities for natural gas. PHMSA has stated publicly that interim regulations will be issued in 2016 (PHMSA, 2016a).

5.3 REVIEW OF CURRENT STATE REGULATIONS RELATED TO GAS STORAGE FACILITIES

State Level Regulations by Reservoir Type

Although there has been a lack of clarity on the authority of state regulatory jurisdiction over natural gas storage facilities, many states have enacted rules covering the intrastate natural gas storage facilities within their borders. For this study, 19 states with natural gas storage fields were selected for an analysis of state level natural gas storage regulations, with ~90% of all active natural gas storage wells are located in these jurisdictions. Of these 19 states, 11 states have regulations specifically addressing surface or subsurface infrastructure within such facilities. Four of these 11 states have regulations addressing underground natural gas storage in all three reservoir types: depleted fields, aquifers, and salt caverns. Further detail on state level regulations regarding natural gas storage by storage field type is shown in Table 5.

Table 5: States with regulations addressing underground natural gas storage based on storage type. Based on analysis by Ground Water Protection Council (2016); The Revisor of Statutes, State of Minnesota (2015). This subset of 19 states were chosen for analysis because 90% of all natural gas storage wells are located in these states. Note: this is not an exhaustive list. This subset of 19 states were chosen for analysis because 90% of all natural gas storage wells are located in these states. States not on this list may or may not have regulations.

State	Salt Caverns	Aquifers	Depleted Fields
CA			
CO	X	X	
IL		X	X
IN	X		X
KS	X	X	X
KY	X	X	X
LA			
MI	X	X	
MS	X		
NY			
OH		X	X
OK			
PA	X	X	X
TX	X	X	X
UT			
WV			
WY			
IA			
MN		X	

The existence of state regulation regarding a specific type of storage facility does not always relate to the type of facilities in the state. Colorado, Kansas, and Pennsylvania each have regulations addressing salt dome storage facilities, yet these states do not presently have salt reservoir storage within their borders. Conversely, Louisiana had an annual salt storage reservoir capacity of 297,020 million cubic feet, but no regulations. Similarly, several states have aquifer storage regulations, but no active storage; or have aquifer storage but no regulation of these facilities. Finally, several states with depleted field storage capacity do not presently have regulations. Details of annual gas storage capacity by reservoir type are shown in Figure 14. Details of the criteria used to determine whether a regulation addresses a specific type of storage facility are described in Ground Water Protection Council (2016).

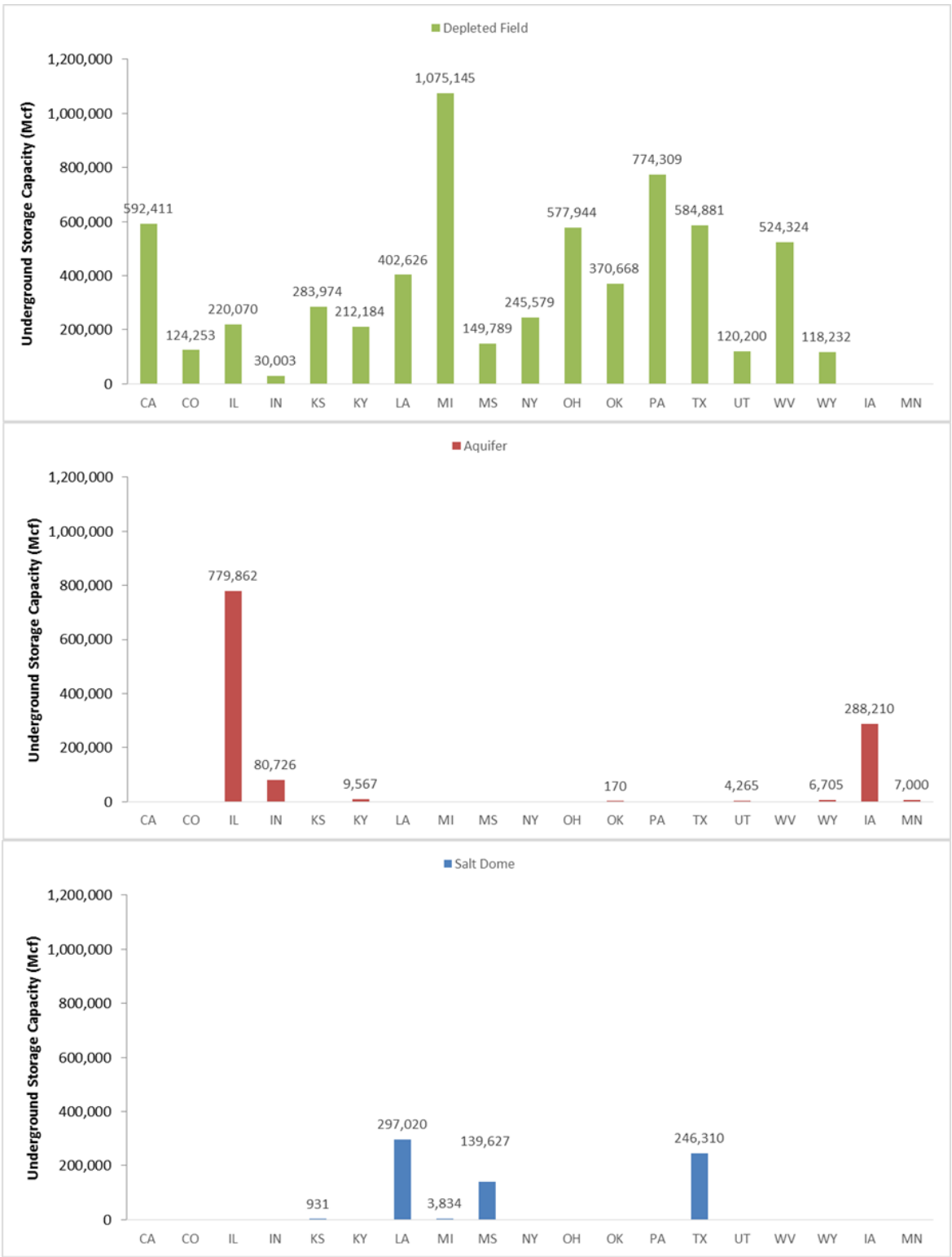

Figure 14: 2012 state level natural gas storage capacity (mcf) by reservoir type (U.S. EIA, 2016a).

State Regulations Related to Natural Gas Storage Wellbore Integrity

Wellbores are the primary engineered pathway linking the subsurface and surface. Maintaining the integrity of these wells across their lifespan—from initial design and construction, through use, and finally plugging and abandonment—is of critical importance for mitigating risk of leakage. Several—but not all states—with natural gas storage facilities have implemented regulations that address wellbore integrity at these stages (Table 6). Only California, Kansas, and Pennsylvania have regulations addressing well integrity at all three stages. At the design and construction phase, Kansas regulation requires a drilling and completion plan to be signed by a professional engineer or geologist. At the operations and maintenance phase, Kansas has requirements for pressure testing, leak detection, and the presence of a safety plan. Finally, Kansas requires specific plugging and completion procedures for all natural gas storage wells (T. S. C. Commission and O. T. S. O. Kansas, 2006). In Pennsylvania, there are several gas storage well design and construction rules: Specific casing and cementing procedures, blowout prevention equipment rules, and storage well construction requirements are all prescribed by the state (State of Pennsylvania, 2012). At the operation stage, Pennsylvania requires mechanical integrity testing every 5 years; geophysical logging and pressure testing, and leak and corrosion inspections. Finally, Pennsylvania requires bridge plugs above and below the gas storage reservoir during the plugging and abandonment of natural gas storage wells. The California proposed rulemaking for natural gas storage wells at the design and construction phase requires primary and secondary well barrier construction (including production casing to surface; tubing and packer; and surface controlled subsurface safety valves). At the operations stage, the draft rules as well as interim emergency regulations in California require mechanical integrity testing (temperature and noise log, as well as casing thickness inspections), as well as monitoring and inspections for leaks. The interim emergency regulations do not have specific requirements for plugging and abandonment protocols; however, the Division of Oil, Gas and Geothermal Resources (DOGGR) remains vested with the authority to oversee the plugging and abandonment of these wellbores (State of California, 2016).

In some cases, states have developed regulations particular to ensuring the integrity of injection wells, but have specifically excluded gas storage wells from these regulations. In the case of the Michigan Department of Environmental Quality Oil and Gas Regulations, injection wells are required to (1) utilize adequate tubing and packer (R 324.801), (2) have an annulus integrity pressure test performed (R 324.803) prior to authority to inject and (3) be subject to repeat pressure testing at intervals not greater than 5 years (R 324.805). However, gas storage wells are specifically exempted from these requirements. Similarly, in California, UIC regulated injection wells were required to undergo pressure testing at least every 5 years, however gas storage wells were exempt from this requirement. This may change, however, as California has a new rulemaking underway at this time.

Table 6: States with regulations regarding natural gas storage well construction, maintenance, and plugging and abandonment as of August 2016. The California regulations are interim emergency regulations (Ground Water Protection Council, 2016; The Revisor of Statutes, State of Minnesota, 2015; State of Iowa, 2016).

State	Well Construction	Well Maintenance	Plugging and Abandonment
CA	X	X	X
CO			
IL	X		X
IN			
KS	X	X	X
KY			
LA			
MI	X	X	
MS	X		
NY			
OH	X		X
OK			
PA	X	X	X
TX		X	
UT			
WV			
WY			
IA	X	X	X
MN			

Review of incidents involving gas storage wells in the U.S.

The following sections highlight two major incidents related to catastrophic leaks from natural gas storage wells, as well as review overall statistics on natural gas well leakage events. Although overall incident rates of catastrophic events (those causing human mortality or substantial damage to human communities) are shown to be demonstrably low, the potential loss of life and damage to infrastructure can be significant.

Aging Infrastructure: The Yaggy Incident

Although the vast majority of natural gas storage facilities operate reliably and safely, there have been, in addition to the Aliso Canyon leak, a small number of notable leakage and/or explosion incidents. Exploring past incidents can generate lessons learned to help clarify the need for the development of rules and best management practices. The 2001 Yaggy Field incident in Hutchinson, Kansas (which led to the promulgation of the Kansas rules for natural gas storage

facilities), is perhaps the most notable of such incidents. This incident occurred on January 17-18 of 2001. Here, natural gas stored in underground salt caverns escaped and migrated laterally more than 8 km through a porous underground geologic formation, where it came into contact with several abandoned wellbores used long before as brine wells. The gas escaped through these wellbores and caused two separate explosions in Hutchinson. Two people were killed, and several businesses were destroyed in the explosions (Wright, 2010). At the time of the 2001 explosions, there were roughly 70 wells penetrating the Yaggy field, 20 of which were newer wells. All wells in the field were drilled to depths of 152–274 meters below the surface. The Yaggy incident highlights the critical role of wellbores (particularly older, improperly abandoned, and structurally unsound wellbores) as a conduit for fluid flow, as well as the critical need to address wellbore integrity to reduce future risks related to natural gas storage. The Kansas Geological Survey investigated the incident, and determined that the leak was a result of damaged casing in one of the older wellbores. The casing damage was determined to have occurred from the re-drilling of an old, cemented wellbore when the Yaggy field was reopened (Allison, 2001). The Yaggy incident also highlights the importance of considering proximity to population centers when planning, inspecting, and managing natural gas storage facilities. Potential risk to human health and other human infrastructure depends heavily on geospatial proximity: natural gas storage facilities located near population centers may require additional considerations for regulations and management to reduce risks. The importance of population center proximity relative to natural gas storage facilities is discussed in the recommendations section of this report.

Newer Infrastructure: The Moss Bluff Incident

The Yaggy incident illustrates risks associated with aging wells and infrastructure in natural gas storage fields. However, newer infrastructure has also been associated with failures and leaks. One such example is an incident that occurred on August 19, 2004, at the Moss Bluff storage facility in Liberty, Texas. The Moss Bluff field is a 640-acre salt cavern storage facility, comprised of three separate underground caverns. Here, a wellhead fire and explosion occurred, releasing 6 billion cubic feet of natural gas. Prior to the explosion, the storage cavern was operating in "de-brining" mode, wherein brine is extracted as natural gas is injected. The brine is transported to the surface through an 8 5/8 in. brine string. The cause of the explosion was determined to be due to a separation of the production casing (well string) inside the cavern. When the brine reached the separation point in the casing, pressurized gas entered the string, where it was brought to the surface through an 8 in. brine piping off of the wellhead. Although the wellhead assembly properly closed when the pressure change was detected, the mechanical force produced by the rapid change in flow rate causing a breach in the piping which was already weakened from wall loss due to internal corrosion (Duke Energy, 2004). The pipe was only 4 years old at the time of the event.

Other Incidents

In a 2008 report by the British Geological Survey (Health and Safety Laboratory, 2008), 64 incidents at underground storage facilities were identified worldwide: 27 in salt caverns; 16 in aquifers; and 16 in depleted fields. Out of these 64 incidents, 17 are classified as catastrophic failures. Failure rate ranges were calculated for well and well casing incidents, and the results of this study are reproduced in Table 7 below. Well failures are defined in the report as releases from leaky or failed boreholes, casing failures, and valve failures (including the piping connecting the underground storage reservoir to the surface).

Table 7: Calculated failure rates for catastrophic well failure. Reproduced from Table 6 in Health and Safety Laboratory (2008)

		Salt Caverns Europe	Salt Caverns Worldwide	Oil/Gas Fields Europe	Oil/Gas Fields Worldwide
Number of well failures		1	10	1	5
Operating experience (well years)	Upper Lower	65,000 24,000	83,000 59,000	153,000 81,000	860,000 603,000
Failure rate (per well year)	Lower Upper	1.5×10^{-5} 1.2×10^{-4}	1.2×10^{-4} 1.7×10^{-4}	6.5×10^{-6} 1.2×10^{-5}	5.8×10^{-6} 8.3×10^{-6}

Another report published in 2004 (Hopper, 2004), identified "catastrophic" events involving salt cavern storage facilities since 1972. Five events were identified where loss of life or serious injuries and property damage occurred. Three of these incidents were due to casing failures; one to packer failure; and one to valve failure. Five other events were identified where only catastrophic loss to property occurred. Two such events were from casing failure; one from valve failure; one from salt creep; and one from a failed mechanical integrity test.

The failure rates discussed above, and causes thereof, illustrate potential vulnerabilities in natural gas wellbore design and specifications. However, there are likely a number of failures of varying significance that have occurred that have not been reported and that were not taken account in these statistics because well failures are not required to be reported in a number of jurisdictions. It is recommended that information on wellbore failures of any kind by recorded and collected by a public agency or agencies so that more accurate statistics may be available. Such data can be aggregated across many locations to help understand the relationships between completion, monitoring, and maintenance practices and well failures and enable improved risk-based management plans. Casing and barrier integrity should be considered as part of a natural gas wellbore risk management plan, as should proximity to population centers.

5.4 GAS STORAGE WELLS IN THE UNITED STATES – DATA AND ANALYSIS

Spatio-temporal Analysis of Gas Storage Well Completions

Characterizing spatial and temporal trends in natural gas well drilling data is important for developing efficient science based management plans for wellbore integrity. The nearly 10,000 wells included in the IHS database (IHS, 2016) were used as part of this analysis to simplify the process of data extraction. Nonetheless, there are several challenges in evaluating trends in these data. Multiple uncertainties in the data quality exist. Many wellbores presently in use for natural gas storage were initially completed for other uses, and permitting and registration of these wellbores will vary based on the year it was drilled, and the state in which it was drilled (Glosser et al., 2016). The structural integrity of wellbores is at least partially related to its age: older wells are generally less likely to have been constructed with redundant barriers, and are more likely to have age or pressure cycle related degradation (Dilmore et al., 2015). Of course, actual structural integrity may also differ by location, and on a case by case basis. Nevertheless, a first order analysis of wellbore records either drilled as—or converted to—natural gas storage wells,

can benefit risk management planning, and inform the need for more detailed investigation of specific regions or wells.

Figure 15 displays temporal trends in gas storage well records. Out of 9,766 wells characterized as natural gas storage wells (IHS, 2016), 4,968 were drilled between 1950 and 1979. Several natural gas storage wells however, were drilled as early as the 1880s and 1890s: with 7 and 32 of such wells presently in operation respectively. In addition, there are 723 wells which do not have an age associated with them, and 166 of these wells are characterized as abandoned. It is likely that these are older wellbores. About 80% of wellbores characterized as natural gas storage wells with known completion years were drilled before 1980. Although no firm cutoff can be stated for what constitutes an "old" well based on its completion year, wellbore construction materials and practices for all wells will be vestigial to the year it was drilled. Hence, the vast majority of the natural gas storage wells presently in use predate modern materials and technology standards; and they have experienced the thermal and mechanical stresses from injection and withdrawal of natural gas across multiple decades. Also, there were no consistent casing design safety standards for pressure containment for older wells.

It is important to note that there are likely to be a substantial number of wellbores penetrating natural gas storage fields that are not presently in use as natural gas storage wells. These wells may be abandoned but unplugged, abandoned and plugged using old standards (i.e. cedar plugs), stripper producers, wells with unknown or questionable ownership, or simply wells that are forgotten (Dilmore et al., 2015). Any risk analysis plan should include a characterization of all wellbores in these regions.

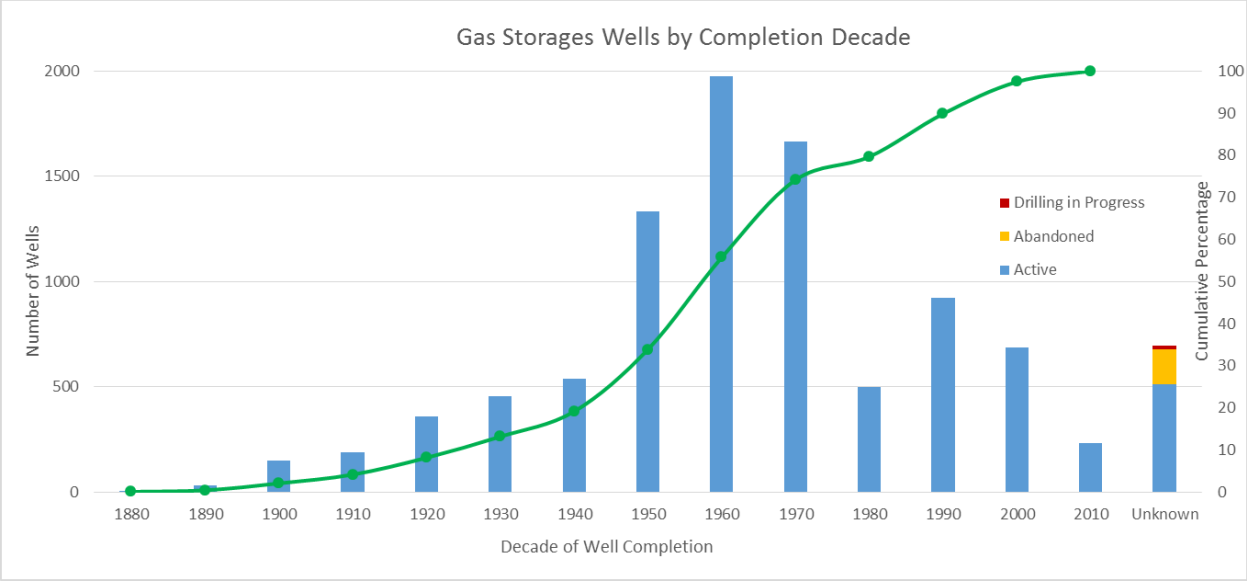

Figure 15: Number of natural gas storage wells permitted per decade.

The relationship between wellbore age and the depth of the wellbore is shown in Figure 16. Depth is an important factor to consider relative to wellbore integrity, because it is related to the likely potential pressure of the subsurface environment. Formation overburden pressure generally increases with depth according to a local hydrostatic pressure gradient (Ladva et al.,

2015; Shaughnessy et al., 2003). The regional stress gradient is also a consideration, because the lateral pressure on a pipe varies accordingly over depth based on a lithostatic gradient. Wellbore components in specific regions and at greater depths also may be subjected to higher temperatures in addition to greater mechanical stresses and therefore may be at increased risk for materials failure. There is an increasing trend in wellbore drilling depth over time. Older wells tend to be shallower: Wells completed through the 1930s tend not to exceed depths of ~3,500 ft below surface. As drilling technology improved over time, wellbore drilling depths reached 14,000 ft below surface.

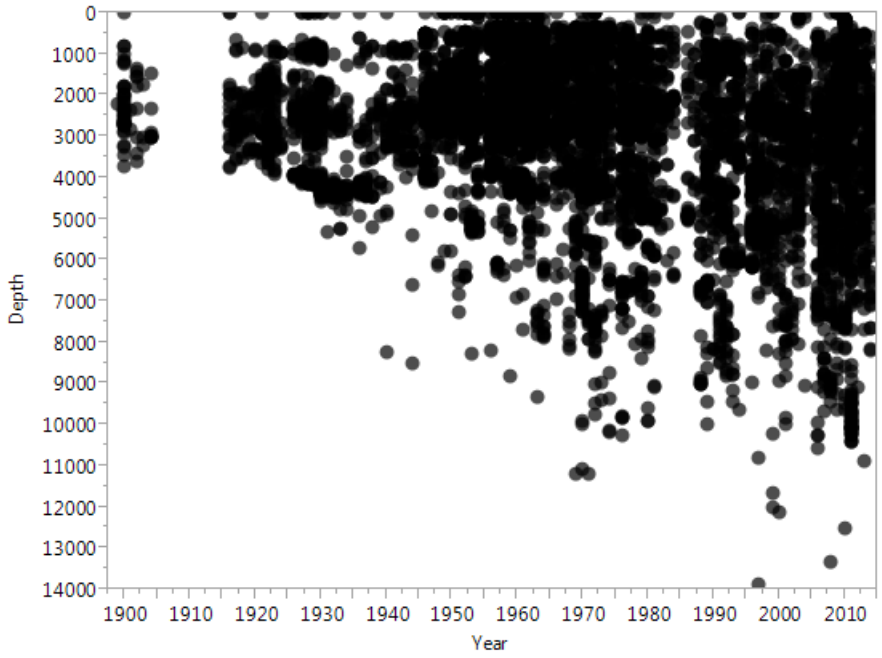

Figure 16: Gas storage wells by year and depth below surface (ft) n=9,771.

The spatial distribution of natural gas storage wells is shown in Figure 17 and Figure 18. Ohio has the greatest number of wells classified as gas storage wells (n=1,772), followed by Pennsylvania (n=1,327) and New York (n=964). Michigan has the greatest number of abandoned natural gas storage wells (n=56). It is unclear whether these results are due to data keeping discrepancies between the states, or whether they reflect the actual proportion of abandoned wellbores across the U.S. It is recommended that state agencies or other stakeholders undertake a thorough investigation of wellbore registration, record keeping, and survey practices in order to better constrain these data (Glosser et al., 2016). Site scale geophysical surveys can also provide additional information regarding potentially undocumented wellbores (Azzolina et al., 2015).

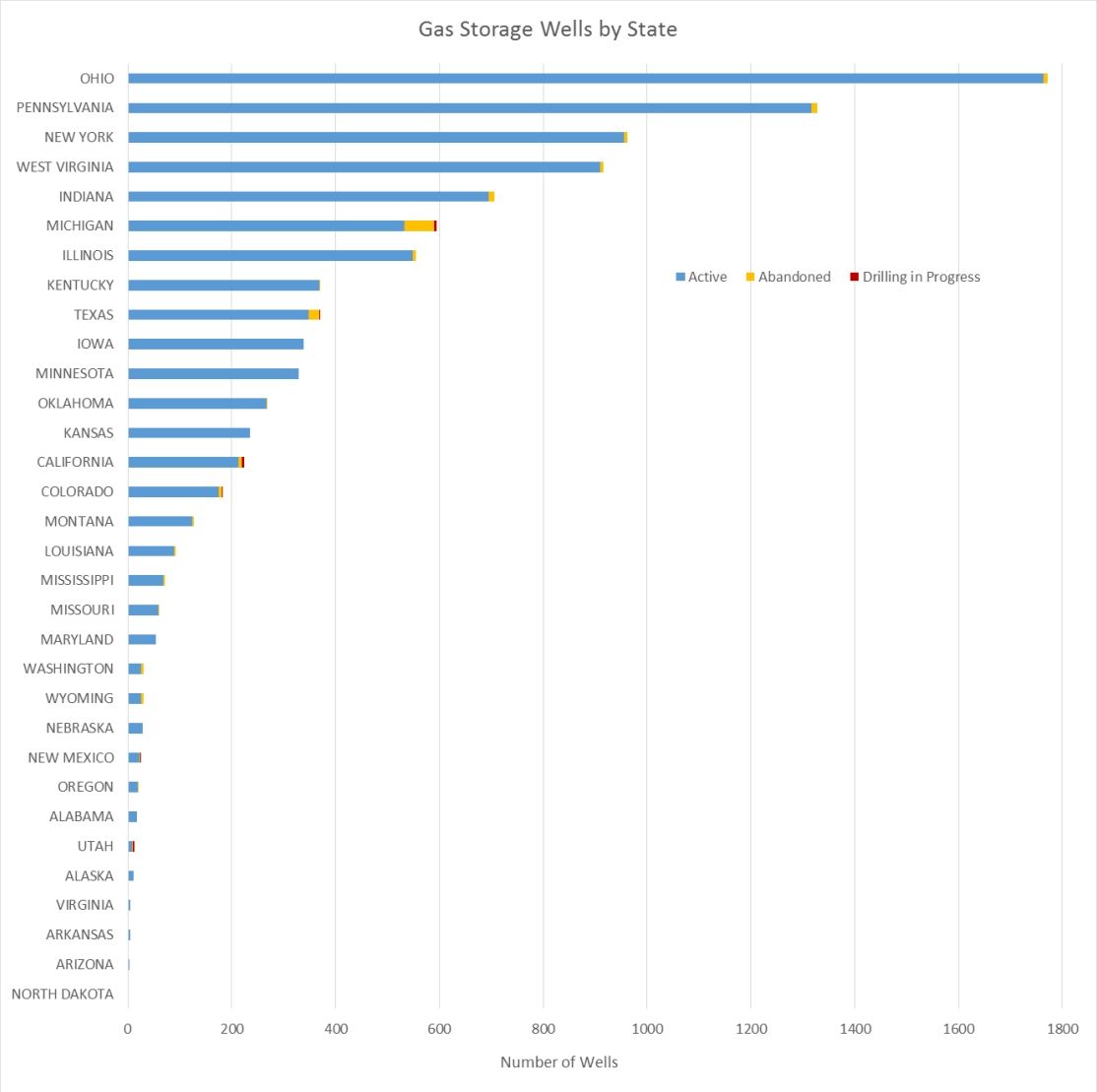

Figure 17: Number of natural gas storage wells in each state, broken out by drilling status.

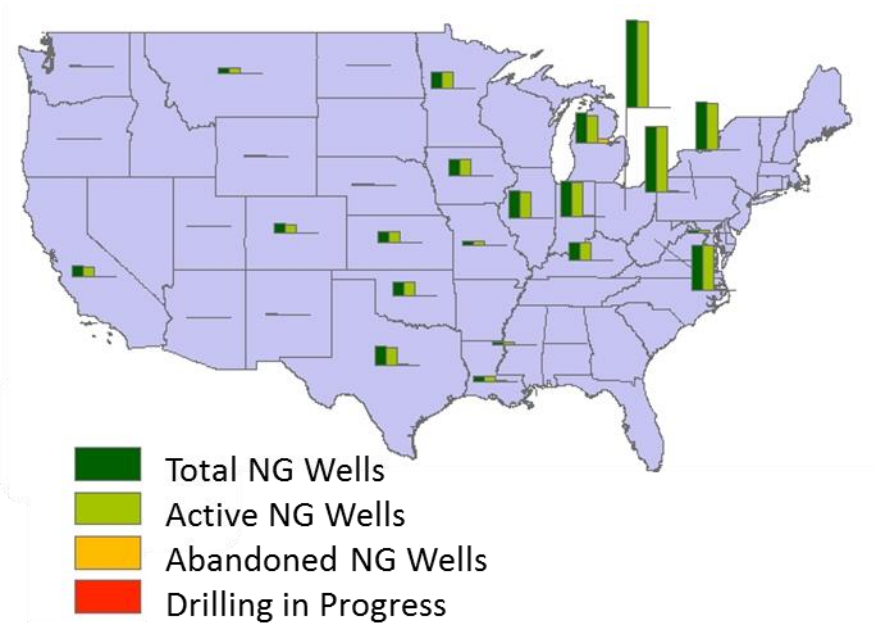

Figure 18: Spatial analysis of natural gas wells.

Gas Storage Wells by Initial Use Type

Several wells penetrating natural gas fields were initially intended for extraction of oil, gas, or both. In addition to the year of completion, the initial well design and construction of these wells is likely to depend in part on its intended original use. The produced fluid type impacts the durability and longevity of the wellbore components: both the mean flow rate and chemical properties of the production fluids influence corrosion and wear impact of tubing, casing, and cement. Based on at least one meta-analysis, mean time to failure (MTTF) analysis suggests that oil production wells are least susceptible to wear impact (King and King, 2013; the subsurface environment and its degree of corrosivity will play a large role. Geoprocessing analysis was performed in order to characterize the initial use type of gas storage wells, except for California well types, which were obtained directly from DOGGR. This analysis was accomplished by geospatial overlay of the wellbore point data reported in this document, with oil and gas field locations maintained by National Carbon Storage Atlas (NATCARB) (NETL, 2016). A 100 m buffer was selected for determining the geospatial association. Wells falling in oil fields were characterized as oil, and wells falling in gas fields as gas. Some clear spatial trends exist: Pennsylvania, Michigan, Ohio, and West Virginia gas storage wells tend to predominantly intersect gas fields. California wells are roughly half gas and half mixed use (oil and gas), whereas Oklahoma has a substantial amount of natural gas storage wells located in oil fields (Figure 19 and Figure 20).

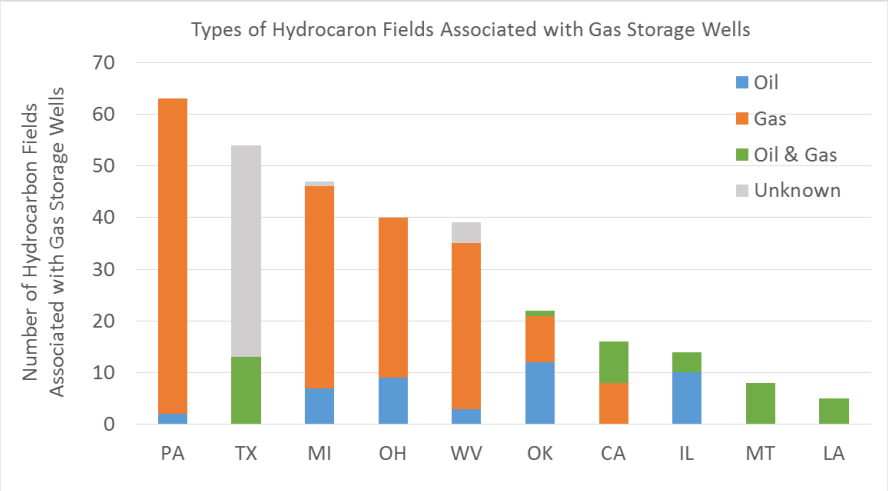

Figure 19: Number of hydrocarbon fields associated with gas storage wells, by state.

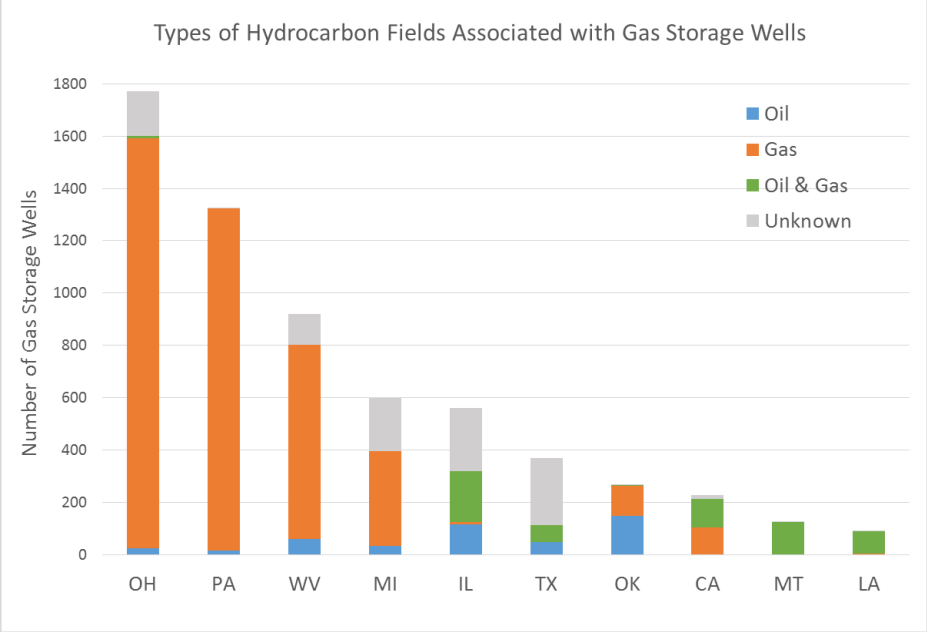

Figure 20: Analysis of initial use and number of wells in gas storage fields by state.

Natural gas storage is an important facet of our nation's energy reliability and security. Developing an understanding of how legacy energy infrastructure (such as older oil and gas exploration and engineering practices) and contemporary uses for these resources interact to inform present day risk is fundamental to developing construction, monitoring, and best management practices to promote human and environmental safety. Legacy uses of natural energy resources crosses jurisdictional and geospatial boundaries in the United States. Sound

policy and procedures for the development of risk reduction activities should consider variabilities in the natural and human histories across these domains.

Natural Gas Storage and Population Nexus

Although rare, large natural gas storage leakage events can have negative impacts on human health and communities. The spatial proximity between human population centers and natural gas storage infrastructure influences the extent and the severity of the risk to human health consequent to such events.

At the national scale, in several areas of the United States, natural gas production or storage wells are near populated areas. Presently, 370 population centers, identified as "Census Designated Places" in the 2010 U.S. census, are within 5 km of an active natural gas storage well (Figure 21) (United States Census, 2016). In other regions, much larger separation distances are possible. This suggests that a graded approach to human health and safety, and therefore a graded approach to gas storage regulations, may be warranted.

National scale distributions of active natural gas storage wells relative to population centers are shown for three separate snapshots in time in Figure 22. The dates (1921, 1979, and present day) are illustrated because they relate to important changes in technological and regulatory innovations. In 1921, zonal isolation became the industry standard for wellbore cement technology (Halliburton, 1921). Prior to this time period, wellbore cement technology was in its infancy. In 1979, several regulatory and concomitant technological innovations relative to environmental protection came to fruition in the United States. In addition, as described in preceding sections, around 90% of all wellbores initially designated as natural gas storage wellbores were drilled by this point in time. Finally, present day data are displayed to highlight current relationships between contemporary population centers and natural gas storage activities. It is clear from this analysis that both population as well as natural gas storage infrastructure has expanded geographically, but the spatial trends in these trajectories are not collinear. Appalachian states, Texas and Midwestern states have, at the larger scale, grown both in population and in natural gas storage infrastructure, whereas in other regions, population growth has not increased as substantially relative to nearby natural gas storage activities.

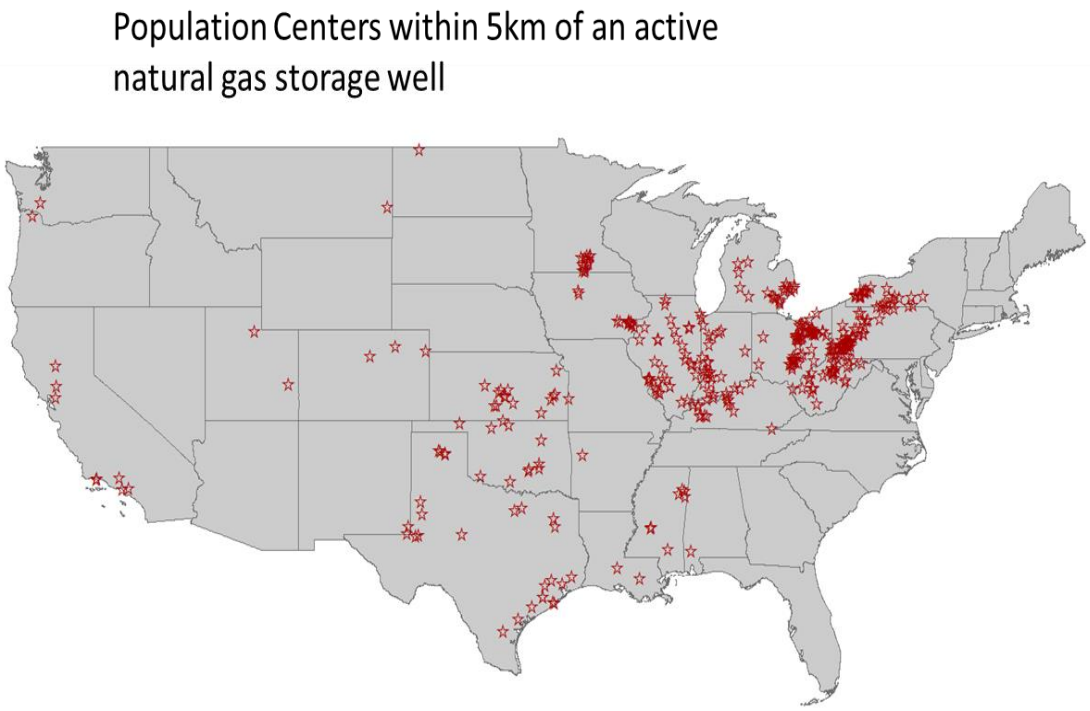

Figure 21: Population centers within 5 km of an active natural gas storage well.

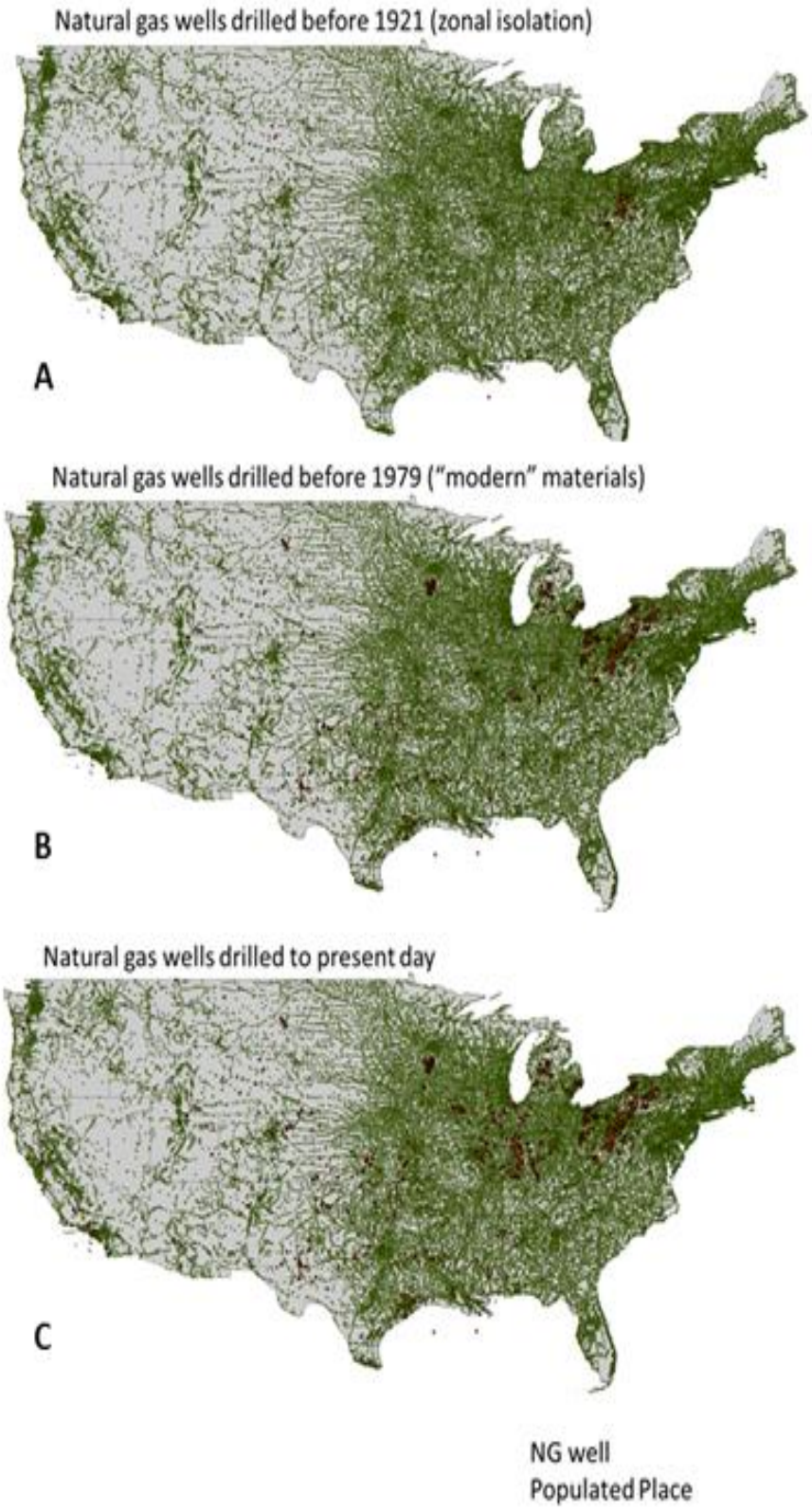

Figure 22: Natural gas well proximity to human population centers.

At the local scale, population encroachment relative to natural gas facilities can also be examined to elucidate the nexus between population centers and gas storage infrastructure. In Pennsylvania, the time dependent expansion of natural gas storage fields is shown relative to changes in county populations for the time intervals of 1900–1920; 1921–1980; and 1981–present (Figure 23). As was the case at the national scale, some regions have shown population growth in areas with increases in natural gas storage infrastructure, while other regions have shown declines in population. For example, the number of active storage fields in Butler County increased from 0 to 3 from the first time interval (1900–1920) to the second (1921–1980). During this time, the population also increased by 90%. In other counties, the relationships are less pronounced. However, these data illustrate the importance of local and regional level considerations of population and human infrastructure relative to the development of regulations intended to safeguard human health in the event of natural gas facility leaks.

Additional insights into the encroachment of population centers on gas storage fields can be seen in Figure 24. Here, tract level census data (University of Minnesota, 2011) are compared in two regions with natural gas storage fields (in California and Michigan). Population growth is observed in several tracts adjacent to the facilities. It should be noted that the tract areas changed between census years, so the actual magnitude of the population density increases may be masked. Nevertheless, the data yield important insights insofar as how regulations and management practices must take into account future potential changes to human population centers relative to natural gas storage facilities.

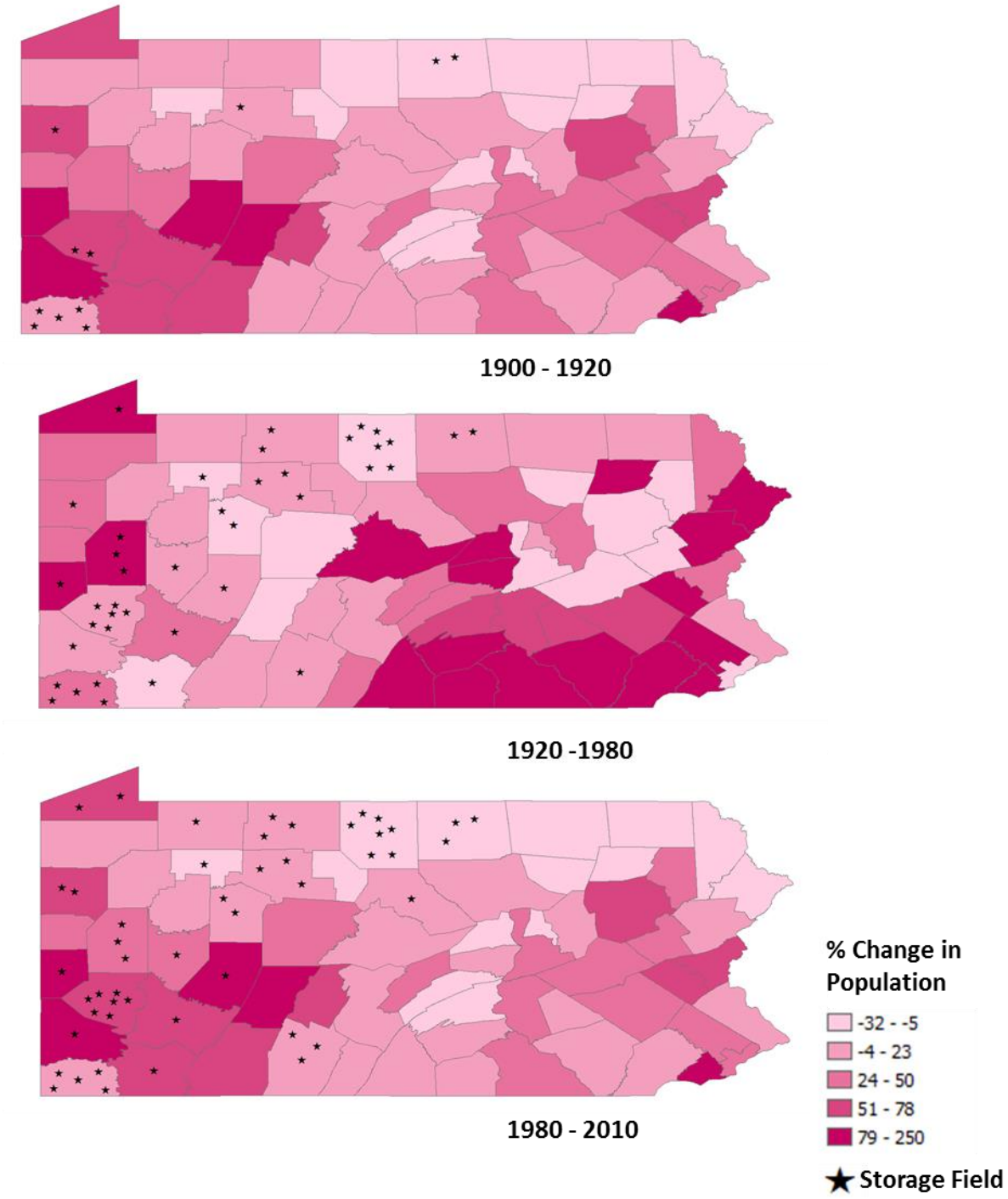

Figure 23: Percent change in Pennsylvania county level population, and the locations of active storage fields during that time period.

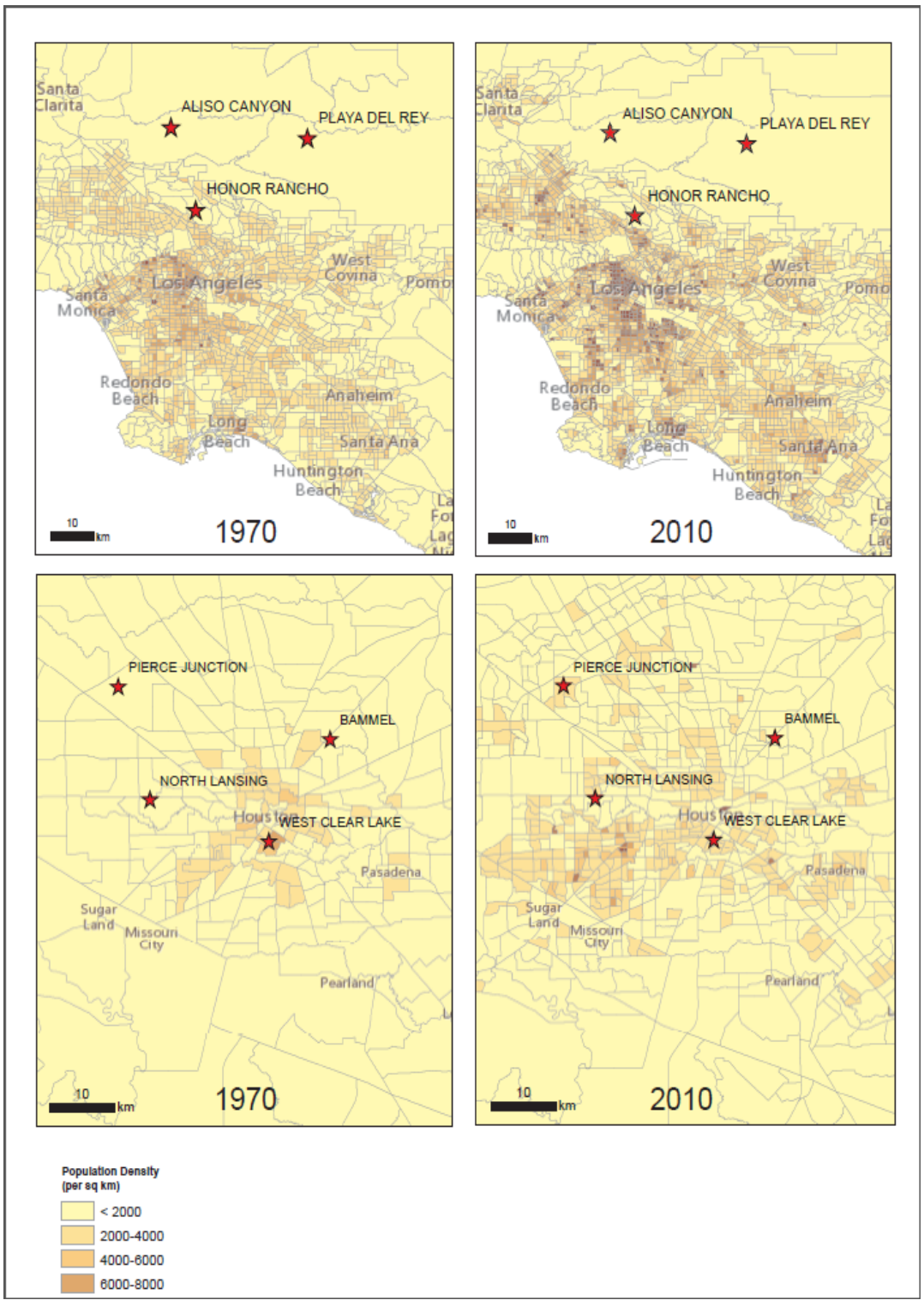

Figure 24: Changes in census tract level population density near gas storage facilities, 1970 and 2010.

6. TASK 4. RECOMMENDATIONS AND CONCLUSIONS

6.1 TOPIC I. WELL INTEGRITY RECOMMENDATIONS

These recommendations are not meant to be comprehensive, but rather to address high priority items the team has identified for reducing the likelihood of future well integrity failures. The ongoing work of the IOGCC in developing a gas storage primer for regulators and the EDF in identifying key elements in gas storage integrity management are meant to be more comprehensive and we recommend any regulatory framework development effort should consider their work product in addition to our recommendations.

Operators should phase out wells with single-point-of-failure designs.

A single-point-of-failure is one in which the failure of a single physical barrier leads to loss of containment from the well. Given harsh subsurface conditions and potentially unreliable engineered components, underground gas storage wells must be designed so that a single-point-of-failure cannot lead to leakage and uncontrolled flow. ISO/TS 16530-2:2014 discusses well barrier design philosophy and provides examples of double-barrier systems that avoid single-point-of-failure criterion. API RP 1171 describes functional requirements for well construction standards, but does not provide clear design criteria. The Draft California Regulations require wells to be designed so that they cannot have a single-point-of-failure that could lead to loss of pressure control. Casing string and cement act as a single barrier system. As such, the authors of this report believe the casing-cement system constitutes a single barrier and does not provide independent double-barrier protection against failure.

Tubing and packer installed within a properly engineered casing string provides one method for achieving a double-barrier system. We recognize, however, that many different well designs can achieve the same fundamental purpose, such as through the use of multiple strings of casing. The most appropriate design will often be site-specific. Frequent testing and monitoring can supplement good double-barrier construction practices to reduce overall risk. A well integrity plan should identify all potential failure scenarios and provide multiple approaches to mitigate these risks (including both physical barriers and monitoring schemes). Sufficient information should be given to regulators for them to make an independent assessment of the effectiveness of these well integrity design and monitoring plans.

New wells can readily be designed to avoid the risks of single-point-of-failure loss of containment. Operators who have existing wells with single-point-of-failure designs should have a risk management plan to maintain safe well operating pressure that includes a rigorous monitoring program, well integrity evaluation, leakage surveys, mechanical integrity tests, conservative assessment intervals, and in most cases a plan to phase out these designs. An operator seeking to continue utilizing a single-barrier well design should prepare and make available for regulatory review during inspections a rigorous and fully documented engineering analysis of the design that considers the potential impacts and consequences of a leak at any point for each well without benefit of a double barrier. For single-barrier wells, the operator should demonstrate that a failure will not lead to pressure that can exceed the fracture gradient of the surrounding formation, and that the design protects water resources. The operator's technical justification for continued use of a single barrier should also include analysis as to why a double barrier is not practicable. While a transition plan to a double-barrier system is being developed and implemented, integrity management procedures with robust safety factors should be

implemented to maintain safe maximum well operating pressures. Well integrity evaluation, risk management plans, and transition plans are discussed further below.

Operators should undertake rigorous well integrity evaluation programs.

As natural gas consumption in the United States has steadily increased over the last two decades, the natural gas storage industry faces the challenge of improving the reliability of their storage infrastructure while continuing to provide consistent and cost-effective service. Infrastructure maintenance and upgrade plans should be prioritized based on relative risk. Risk-based planning requires a complete understanding of the baseline conditions of all wells within a gas storage field, including those currently active, idle and abandoned. Without an adequate baseline, high-risk and low-risk wells cannot be identified with confidence. We recommend that all operators undertake a rigorous evaluation of the current state of their well inventory. This is consistent with PHMSA's advisory bulletin ADB-2016-02 to all operators of underground storage as defined under 49 CFR part 192 to begin a systematic evaluation of all their wells and, in particular, recommended that operators voluntarily implement API RP 1170 and API RP 1171.

Evaluations should include: (1) a compilation and standardization of all available well records relevant to mechanical integrity, (2) an integrity testing program that includes usage of leakage surveys and cement bond and corrosion logs to establish that all wells are currently performing as expected, (3) documentation of a risk management plan to guide future monitoring, maintenance, and upgrades; (4) establishment of design standards for new well casing and tubing; and (5) establishment of safe operating pressures for existing casing and tubing. Many operators already apply these risk management practices in their operations, and these approaches should be applied industry-wide.

Monitoring, logging, and mechanical integrity testing must be top priorities for lowering risk to well integrity, as they provide hard data on well performance.

There are considerable uncertainties in predicting the long-term behavior of wells. It is often noted that some very old wells perform perfectly—despite failing to conform to modern design practices—while some newer wells need frequent maintenance. Given intrinsic variation in site conditions and individual well performance, frequent monitoring, logging, and mechanical integrity testing are essential tools to inform operators about well integrity. If carried out properly, these tests provide hard information about the performance of a well and they can help identify problematic situations and guide mitigation steps before more serious integrity problems develop.

A counter-argument can be made that excessively frequent logging and other well work can raise the overall risk profile when personnel risks and other operational risks are considered. Any type of well work puts personnel at risk of injury. Further, many losses of well control occur during well interventions, when the system is taken outside of its normal operating mode. As a result, overly-frequent logging, testing, and other well work may increase the overall leakage and injury risk. These concerns are valid, but they should not become an easy excuse for failing to perform due diligence with respect to well integrity. Many types of well work can be coordinated so that the number of well interventions is reduced. Good safety procedures can be put in place to protect personnel, and appropriate well control measures can be used when a well is taken outside of normal operations. The focus should be on lowering *all* types of operational risk, rather than viewing them as competing priorities. In the long run, good maintenance procedures

can lower personnel risk by preventing the need for risky blowout-control activities, as were required at Aliso Canyon.

We recommend that yearly noise and temperature logs be run to detect leaks in all wells, unless other methods (such as continually monitoring casing-tubing annulus pressure) are in place to monitor for leaks. As soon as possible, operators should also perform casing wall thickness inspections on all wells for which recent data are unavailable to assess the current state of corrosion and other damage. Using data from this baseline assessment, the frequency of subsequent casing thickness inspections and pressure testing can be determined based on the integrity risk of individual wells and a rational balancing of other operational risks—e.g., potential well damage during workovers, personnel safety concerns, etc. Lower-risk wells should receive less frequent attention in order to focus available resources on the pool of higher-risk wells. Operators should also maintain detailed integrity and maintenance records, and periodically review these records in aggregate to estimate typical corrosion rates and other field-wide trends in well performance. These aggregate trends should also inform the frequency of logging and mechanical integrity testing.

Well integrity testing should use a tiered approach with a goal of minimizing total risk, which includes risks to storage integrity associated with the testing, risks to personnel, etc.

Well integrity testing should be executed with the goal of minimizing total risk to storage integrity, personnel, etc. To address concerns that frequent logging and other well work might increase risk, note that many types of well work can be coordinated so that the number of well interventions is reduced. Good safety procedures and safety training can be instituted to protect personnel, and appropriate well control measures can be used when a well is taken outside normal operations. Specifically, the risks associated with downhole measurements and other interventions (e.g., damage to well, injury to personnel) should be weighed against the benefits. To that end, integrity testing should use a tiered approach where less invasive, routine testing (such as noise and temperature logging) is performed more frequently and more comprehensive testing (such as pressure and casing inspection) less frequently and as-needed.

Well integrity testing should use multiple methods and not rely on a single diagnostic.

Using a single diagnostic tool to assess well integrity can result in overlooking adverse well integrity conditions and incipient or impending failures. Temperature and noise logs are used ubiquitously in NGS to identify leaks, but the sensitivity of the measurements is limited and the data provide no hint of impending problems. Casing corrosion logs and cement bond logs can identify integrity defects and a time-progression of casing diagnostics can identify where well integrity is deteriorating. However, casing diagnostic logs provide no information concerning whether a leak is ongoing. A pressure test can identify a casing leak below the sensitivity of temperature and noise logs, but that test alone provides no spatial information as to where that leak is occurring. An ideal well integrity testing program will incorporate multiple methods that recognize the benefits, limitations and complementary nature of data from each diagnostic test. The optimal diagnostic program will be site-specific and may change over time as data are collected and evaluated.

Storage operators should deploy continuous monitoring systems for wells and critical gas handling infrastructure.

New sensors and monitoring systems, along with IoT (Internet of Things) technology, are available to monitor, measure, diagnose, notify, and respond to changes in gas storage field conditions. These technologies are decreasing in cost and becoming easier to use. These technologies can allow a gas storage field to be operated as remotely as desired, similar to other high-hazard industrial facilities, and any necessary engineering, safety, or emergency responses can be immediate. It must be noted, however, that automated control and management systems have cyber vulnerabilities that pose security risks for this vital national asset.

Thus, gas storage operators should deploy continuous monitoring systems at the ground surface and through the multiple casing strings for wells and critical gas handling infrastructure. This includes monitoring of annular and tubing pressure, as well as surface leak detection. Potential cyber security risks should be addressed as part of an operator's risk assessment, especially if the monitoring network is tied to a real-time control system.

6.2 TOPIC II. RISK MANAGEMENT RECOMMENDATIONS

Risk management is an ongoing process for management of events that have some probability of occurring that could have an adverse impact. Gas storage operators should implement formal risk management plans that document their risk management strategy, identify risks, define stakeholder responsibilities, assesses risks and provides appropriate responses. A risk management plan will also include the mitigation steps that will be undertaken to lessen the probability of adverse events occurring or to mitigate their impacts. As risk management will be needed for the life of a project, the plan needs to include a methodology by which its effectiveness can be tracked, reported and by which the plan can be periodically reviewed and updated. We have included recommendations for strengthening risk management because subsurface risk management plans have been implemented inconsistently across the industry. API RP 1171 presents an overview of elements that should be considered in a gas storage risk management plan. ISO/TS 16530-2:2014 discusses risk management but focuses more narrowly on well integrity management, which is one of several key elements in a broader risk management plan.

Risk Management Plans should be comprehensive and reviewed periodically.

The gas storage community is making significant progress in developing and implementing processes that manage risk. This progress can be attributed to contributions from operators, regulators, industry associations, and other experts. Risk assessments have inherent limitations in that they cannot account for unknown threats and they often rely on assumptions and/or estimates. Effective risk management relies on continuous improvement to ensure that decisions are based on current information and the most relevant methods.

Risk management plans need to be comprehensive and address risks based on potential severity and likelihood of occurrence. While the Well Integrity recommendations introduced as Topic I above are focused specifically on well design, construction and operation, gas storage operators need to consider risks much more broadly. In addition, emergency response plans need to be ready for addressing high consequence risks and key stakeholders need to be brought into the risk management process. Gas storage operators should implement formal risk management plans that document their risk management strategy, identify risks, define responsibilities among stakeholders, assess risks, and provide appropriate responses. A risk management plan should include preventative and mitigation measures. As risk management will be needed for the life of

a project, the plan should include a methodology by which its effectiveness can be tracked and reported, and by which the plan can be periodically reviewed and updated. We recommend that regulators or their proxies independently review and approve operators' risk management plans at regular intervals as part of the inspection and oversight process in order to enhance the continuous improvement process. The inspection and oversight process should prioritize and adjust inspection frequency based on level of risk. The inspection and oversight process should also include a periodic review cycle to adjust methods, based on data collected through the inspection and enforcement process and other means.

Operators should institute complete and standardized records management systems.

Underground gas storage operators should establish a records management process to ensure that documentation of essential information is created, maintained, protected, and retrievable when needed. Essential information consists of all records related to evidence of compliance with statutory and regulatory requirements. Operator data should include detailed well-completion diagrams, including casing and tubing strength, wall thickness, and coupling type schedules, maximum and minimum allowable operating pressures, safety valve locations and testing results, maximum withdrawal and injection rates, reservoir depth, well maintenance records, and incidents of failure.

These records should be maintained for the lifetime of the facility. Records management processes should establish a filing and storage strategy that ensures records are accessible and protected against environmental damage. Records may exist in many different formats and should be managed according to the format in which they are maintained. Records may be protected following a graded approach, commensurate with the value of the record and the cost to reproduce the information.

Critical information that should be preserved for the life of a facility includes findings of conditions adverse to the integrity of a well, whether or not the condition led to a release or required mitigation. Records should include information about the factors that contributed to the adverse condition, and in the event of a leak, the failure mechanisms, the size and duration of the leak, the conditions under which the leak occurred, the age and condition of the well and its maintenance schedule. Such data can be aggregated across a field, as well as industry-wide to provide help in understanding the relationships among completion, monitoring, and maintenance practices and well failures and enable improved risk-based management plans. Aggregating integrity data can inform risk-based management practices and lead to optimization of operations that can further reduce risk.

The records management processes should allow an operator to track records throughout their entire information life cycle so that it is clear at all times where a record exists, which is the most current version of the record, and the history of change or modification of the record. The processes should ensure appropriate identification and description of records including information such as title, date, author, reference number, etc. when records are created or modified. Record change control (version control) processes should be established to ensure that records are changed in a controlled and coordinated manner.

Operators should develop and implement risk management transition plans within one year from the date new minimum federal standards are issued to compliance.

The activities required to reach conformance with new requirements will compete for resources with other risk-mitigation investments. Industry organizations estimate that the gas storage community will require 7–10 years to reach full conformance with API RP 1171 (API, AGA and INGAA, 2016). It is recognized that operators must contend with gaps that may exist for their operations relative to newly developed requirements and guidelines. We recommend that operators be required to develop and implement a transition plan within one year of the date of adoption of new regulations/standards. The transition plan should describe planned activities and a schedule that will be followed to reach compliance. The plan should address how activities are prioritized so as to mitigate overall risk, and they may include enhanced monitoring measures that operators can use during transition to mitigate risks. Regulators should inspect operators' records during routine inspections in an effort to ensure that the transition plans have been properly implemented.

Operators and regulators should account for a broad range of risk factors. API RP 1171 mentions the use of procedures and training as mitigation measures for controlling risk. It also mentions that procedures and training can embed human and organizational competence (human factors) in the management of storage facilities. Human factors are an important consideration in avoiding errors that can lead to accidents. API RP 1171 does not provide guidance or recommendations related to human factors and provides very general guidance for developing procedures and training. One of the workshop presenters indicated that human factors is one of the "future directions" that the API RP 1171 Committee has discussed. Risk management and emergency response plans should consider human factors in procedures and training.

The underground storage community should pursue human factors as a future direction. There is an existing body of work that has examined human factors (or similarly, human performance, safety culture, etc.) in many contexts. There should be a goal to create guidance within 10 years that discusses the use of human-factor principles in mitigating risk in underground gas storage facilities.

Given the complex interrelationship between natural gas infrastructure, well integrity, and natural systems, risk management plans should be able to detect/anticipate scenarios that resemble historical events (e.g., Aliso Canyon) but should also attempt to address vulnerabilities that have not yet led to major events. For example, in some parts of the country, severe weather events, such as hurricanes, tornadoes, and floods can pose risks to gas storage wells and fields. In other cases, seismic activity and/or landslides can pose a risk. Addressing these disparate risks is best achieved through rigorous implementation of an objective risk assessment using independent review that accounts for uncertainties rather than simply applying reactive protocols to address specific scenarios. The proximity of human population centers or infrastructure relative to gas storage facilities will necessarily be a factor in this calculation.

6.3 TOPIC III. RESEARCH AND DATA GATHERING RECOMMENDATIONS

A quantitative cost-benefit analysis of downhole safety valves is needed to resolve uncertainty in their benefit for the U.S. natural gas storage industry.

The value of downhole safety valves (DHSVs) for NGS is a source of significant controversy. DHSVs can provide a direct safeguard for preventing many uncontrolled flow scenarios, but their positioning in the well, reliability, and impact on production capacity raise significant concern among operators. While DHSVs have seen widespread use in the offshore oil and gas

industry and in European natural gas storage, it remains unclear if DHSVs should be more widely deployed in U.S. storage facilities. We recommend a quantitative study be commissioned to evaluate key uncertainties in this cost-benefit analysis, including: (a) malfunction and failure rates of modern DHSV designs, (b) the cost and frequency of additional well work associated with their deployment, (c) the frequency of well failures for which a DHSV would provide a sufficient safeguard, (d) alternative emergency valve designs that could provide similar protection, (e) the impact of widespread DHSV deployment on NGS delivery and cost, and (f) optimal placement location(s) in wells for mitigation of well integrity failures. An outcome of work in this area would be requirements and specifications that DHSV manufacturers could use to improve their products.

A systematic study comparing the effectiveness of different casing evaluation tools is needed.

Several casing-wall-thickness logging tools are now commonly used by natural gas storage operators to support well integrity assessments—e.g., various electromagnetic and ultrasonic tools. Industry continues to improve the capabilities of wireline tools, marketing products with higher spatial resolution and the ability to assess multiple casing strings simultaneously. Improving the knowledge on the relative sensitivity, accuracy, and overall effectiveness of these tools will aid in developing optimal integrity management practices and assessing residual risk. We recommend that a systematic study be carried out in which multiple tool types are applied to (manufactured) test articles and one or more reference wells with well-characterized corrosion issues. The goal should be to rigorously test and compare the ability of these techniques to identify, locate, and characterize corroded casing. This study can also inform better log-interpretation practices.

Industry and other stakeholders should review and evaluate wellbore simulation tools

The Aliso Canyon event highlighted potential limitations in existing tools and analytical methods for simulating complex well processes, such as associated with well kill events. As noted in the review of the Aliso Canyon event, the SS-25 completion top kills were hindered by the tortuous fluid pathways governed by both tubing exits and re-entrances. The initial simulations used to support the Boots and Coots top kill efforts lacked sufficient detail to correctly predict that the well kill attempts would fail. Incorporating "real world" conditions in a wellbore simulation, such as complex fluid pathways or high density non-Newtonian fluids, is a challenging task to conduct during a rapidly evolving crisis, particularly with the inherent limitations in knowledge of the boundary conditions and the exact configuration of a damaged well. This is also important because poorly executed top kills can have a detrimental effect on the well condition and future kill attempts.

A review of existing well simulation codes that can be or are currently applied for analyzing adverse well events could be undertaken by DOE, industry, and other stakeholders. The assumptions underlying each code, as well as code adaptability for a variety of geologic and reservoir settings should be carefully considered. Working with industry providers, universities and national laboratories, a set of benchmark problems and well failure scenarios can be developed to exercise the codes and to compare results. Similar code comparison studies have been used in the past to support critical national programs (e.g., radioactive waste isolation). Based on the review of existing analytical capabilities, the identification of knowledge gaps and limitations can then be used to improve the toolkit of software to assist in response to future loss of well control events. Learnings from this should be disseminated at forums, as they are seen as

broadly applicable throughout the oil and gas industry. Ultimately these tools, used by knowledgeable engineers, should be utilized for development of well integrity plans that identify weaknesses in a given design and consider failure modes that could lead to a loss of pressure control.

State agencies or other stakeholders should undertake a thorough investigation of wellbore registration, record keeping, and survey practices.

The records for wellbores that were drilled decades or over a century ago may not be accurate, and could have been lost completely. State and/or federal agencies should consider undertaking data gathering activities in their state to identify the locations of unknown wells, particularly in areas where known exploration and production activities have occurred in the past. This data gathering and record keeping may include site-scale geophysical or ground-truth surveys, as well as the collection and concatenation from multiple historical sources such as maps, property records, leases, or aerial photography. State agencies or other stakeholders should collect data and prioritize the effort by consideration of proximity to population centers relative to new gas storage field facilities, and new wells in existing gas storage fields. In addition, QA/QC effort should be undertaken to evaluate the accuracy of existing databases on well records. As wells are entered and logged as part of the recommendations in this report, the information in databases can be evaluated and updated. We note the well record for the SS-25 well at Aliso Canyon contained ambiguous and likely incorrect information regarding key aspects of the tubing-to-casing connections.

Data should be collected that considers proximity to population centers relative to new gas storage field facilities, and new wells in existing gas storage fields.

Reviewing records for the past 100 years, one finds a number of instances where wells and fields that were originally far from population centers are now quite close to significant numbers of people. The Aliso Canyon event from last year represents a prime example of this. States or federal agencies or other stakeholders should collect and analyze data on the proximity of wells to population centers to better quantify some of the risk factors associated with known well locations. Best management practices and policies should take into account projected changes to land use, infrastructure, and human population centers relative to gas storage facilities. It should be noted that this is not an issue that is germane only to natural gas storage wells, and should be considered for other oil and gas wells, too.

This page intentionally left blank.

7. REFERENCES

API, AGA, INGAA. Underground natural gas storage, integrity and safe operations, July 6, 2016. http://www.energyinfrastructure.org/energy-101/natural-gas-storage

Azzolina, N. A.; Small, M. J.; Nakles, D. V.; Glazewski, K. A.; Peck, W. D.; Gorecki, C. D.; Bromhal, G. S.; Dilmore, R. M. Quantifying the benefit of wellbore leakage potential estimates for prioritizing long-term MVA well sampling at a CO_2 storage site. *Environ. Sci. Technol.* **2015,** *49*, 37–42.

Dilmore, R. M.; Sams, J. I.; Glosser, D.; Carter, K. M.; Bain, D. J. Spatial and Temporal Characteristics of Historical Oil and Gas Wells in Pennsylvania: Implications for New Shale Gas Resources. *Environ. Sci. Technol.* **2015,** *49*, 12015–23.

Duke Energy. *Duke Energy Gas Transmission Presents Investigation Findings of August Moss Bluff Storage Facility Incident: Series of Unusual Events Basis for Natural Gas Release and Fire*; 2004.

G. P. Council. *Summary of Gas Storage Regulations from 17 State Oil and Gas Agencies*; Ground Water Protection Council; April 2016.

Glosser, D.; Rose, K.; Bauer, J. R. *Spatio-Temporal Analysis to Constrain Uncertainty in Wellbore Datasets : An Adaptable Analytical Approach in Support of Science-Based Decision Making*; 2016, pp. 1–19.

Halliburton, E. P. Method and Means for Cementing Oil Wells, US Patent 1369891, 1921.

Health and Safety Laboratory. *Failure rates for underground gas storage*; 2008.

Hopper, J. Gas storage and single-point failure risk. *Energy Mark* **2004**.

IHS. IHS Markit Wellbore Data, 2016. [Online]. https://www.ihs.com/products/oil-wellbore-analysis-optimization-software.html

Iowa Administrative Code. 2016. https://www.legis.iowa.gov/law/administrativeRules/rules?agency=199&chapter=12&pubDate=10-26-2016

ISO/TR 16530-2:2014, Well integrity - Part 2: Well integrity for the operational phase.

King, G.; King, D. Environmental Risk Arising From Well Construction Failure: Differences Between Barrier Failure and Well Failure and Estimates of Failure Frequency Across Common. SPE Annu. Tech. Conf. Exhib., Oct 2013; SPE–166142–MS.

Ladva, H.; Craster, B.; Jones, T.; Goldsmith, G.; Scott, D. The Cement-to-Formation Interface in Zonal Isolation. *SPE Drill. Complet.* **2005,** *20*, 13–15.

Lee, A. M. The Hutchinson Gas Explosions: Unraveling a Geologic Mystery. Kansas Bar Association, 26th Annual KBA/KIOGA Oil and Gas Law Conference, 2001, 3-1–3-29.

Minnesota Population Center. *National Historical Geographic Information System: Version 2.0*. University of Minnesota: Minneapolis, MN, 2011.

NETL. NATCARB, Carbon Storage Atlas, National Energy Technology Laboratory, [Online]. Available: http://www.netl.doe.gov/research/coal/carbon-storage/natcarb-atlas

Niska Gas Storage. Gas Storage Industry Primer, 2010. www.niskapartners.com/wp-content/uploads/2010/04/GasStorageIndustryPrimer.pdf (accessed Sept 1 2016).

PHMSA. Pipeline Initiatives, 2016a. [Online]. Available: http://www.phmsa.dot.gov/pipeline/initiatives/partners.

PHMSA. Pipeline Safety: Safe Operations of Underground Storage Facilities for Natural Gas; 2016b.

Shaughnessy, J. M.; Romo, L. A.; Soza, R. L. Problems of Ultra-Deep High-Temperature, High-Pressure Drilling. SPE Annual Technical Conference and Exhibition, 2003; pp. 1–9.

State of California. DOGGR, 2016. http://www.conservation.ca.gov/dog/Pages/AlisoCanyon.aspx

State of California. DOGGR, 2016. http://www.conservation.ca.gov/dog/Pages/AlisoCanyon.aspx.

State of California. Onshore Well Regulations; 2016. http://www.conservation.ca.gov/index/Documents/2016-03%20Emergency%20regulations%20for%20natural%20gas%20storage%20wells%20go%20into%20effect.pdf

State of Kansas. *General Rules and Regulations for the Conservation of Crude Oil and Natural Gas*; State Corporation Commission of the State of Kansas, 2015. http://cdm16884.contentdm.oclc.org/cdm/ref/collection/p16884coll36/id/113

State of Pennsylvania. Oil and Gas Wells; 2012. http://www.pacode.com/secure/data/025/chapter78/chap78toc.html

State of Texas. *Underground Storage of Gas in Productive or Depleted Reservoirs*; Rule §3.96 Texas Administrative Code; 2012. https://texreg.sos.state.tx.us/public/readtac$ext.TacPage?sl=R&app=9&p_dir=&p_rloc=&p_tloc=&p_ploc=&pg=1&p_tac=&ti=16&pt=1&ch=3&rl=96

T. S. C. Commission and O. T. S. O. Kansas, *General Rules and Regulations for the Conservation of Crude Oil and Natural Gas*; 2006.

The Revisor of Statutes, State of Minnesota. *2015 Minnesota Statutes*. https://www.revisor.mn.gov/statutes/?id=103I.681

U.S. EIA. Gas Storage Capacity [Online]; 2016a. https://www.eia.gov/dnav/ng/NG_STOR_CAP_A_EPG0_SA6_MMCF_A.htm.

U.S. EIA. Natural Gas Underground Storage Facilities, updated December 5, 2016b https://www.eia.gov/maps/layer_info-m.php (accessed December 8, 2016).

U.S. Supreme Court. *Schneidewind v. ANR Pipeline Co*, vol. 485 U.S. 2. 1988.

United States Census, 2016 [Online]. https://www.census.gov/geo/reference/centersofpop.html.

United States District Court, S.D. Illinois. *Petco Petroleum v Natural Gas Pipeline Company of America*; 2011 WL 17; 2011.

Wright, T. E. CIG v. Wright; No. 09–403; 2010, pp. 1–49. https://casetext.com/case/colorado-interstate-gas-company-v-wright

APPENDIX: REQUIREMENTS OF COMPREHENSIVE SAFETY REVIEW OF ALISO CANYON NATURAL GAS STORAGE FACILITY

California Department of Conservation, Division of Oil, Gas and Geothermal Resources

Since October 25, 2015, no natural gas has been injected into the Aliso Canyon Gas Storage Facility. Pursuant to the Governor's Order of January 6, 2016, all injection activity into the Aliso Canyon facility remains suspended until a "comprehensive review, utilizing independent experts, of the safety of the storage wells" is completed. This document summarizes the requirements of this comprehensive safety review.

The Department of Conservation, Division of Oil, Gas, and Geothermal Resources (Division) has consulted with independent technical experts from the Lawrence Berkeley, Lawrence Livermore, and Sandia National Laboratories ("National Labs") to develop the requirements of this facility safety review. The National Labs experts independently reviewed and concurred with the testing requirements for the safety review detailed below. The Division will continue to consult with these experts throughout the Division's supervision of the implementation and completion of the comprehensive safety review.

This comprehensive safety review requires that each of the 114 active wells in the Aliso Canyon facility either pass a thorough battery of tests in order to resume gas injection or be taken out of operation and isolated from the underground gas reservoir. Several steps, detailed below, are required in this safety review.

REQUIRED TESTS FOR EACH WELL IN THE FACILITY

Step 1: Southern California Gas (operator) shall perform casing assessment on the well consisting of temperature and noise logs.

a. Temperature Log:

A sensor will be lowered down the depth of the well to measure the temperature of the material inside the metal tubing in the well. If the casing in the well is not intact, gas leaking out of the casing will expand and cool, and reduce temperatures within the well. A temperature test that verifies no cooling is taking place in any part of the well indicates that the casing has maintained integrity and no leaks exist.

b. Noise Log

A highly sensitive acoustic sensor capable of detecting the sound of gas flowing will be lowered down the length of the well above the gas reservoir. This sensor will listen for any gas escaping from the well bore. If the well has a leak, gas will escape from the well bore causing a sound that can be detected by the sensor. The absence of sound above the reservoir indicates an effective seal of the well.

Step 2: The results of the Temperature Logs and Noise Logs will be independently reviewed by Division engineers. Any abnormal findings in this set of tests are required to be addressed immediately. For example, if a temperature decrease is noted on a temperature log and further investigation reveals a leak in the external casing of a well, the repair of the well casing must take place immediately. Necessary actions to remediate any abnormalities revealed by these tests will be reviewed by Division engineers. Once repairs or mitigations are completed, the Temperature Log and Noise Log must then be repeated on the well and then once again be reviewed by Division engineers to ensure no additional abnormal test results.

Step 3: After these tests are completed on the well, and any required remediation of the well completed, the operator will either:

a. Conduct a battery of additional required tests and evaluations on the well, outlined below, in order to gain approval for injecting gas through that well; or
b. Remove the well from operation and isolate it from the underground gas reservoir.

REQUIRED TESTS IF A WELL IS INTENDED TO RESUME NORMAL OPERATIONS

If, after the Temperature and Noise Logs are complete, the operator designates a well to return to normal operations, the operator shall perform several additional tests that will be independently reviewed by Division engineers and posted publicly.

Step 4a: The operator will conduct a **Casing Wall Thickness Inspection**.

The Thickness Inspection of the well that measures the thickness of the external casing of a well, as well as the amount of any corrosion that has occurred to that casing. For this test to be conducted, the interior metal tubing is removed from entire depth of the well, and measurements are taken directly from the inside wall of the casing. If the inspection reveals thinning of the casing, the current strength of the casing will be calculated. If the current strength of the casing has diminished to the point that it cannot withstand authorized operating pressures for the well plus a built-in additional safety factor of pressure, the well has failed this test. A passing test for a Casing Wall Thickness Inspection would show no thinning of the casing that diminishes the casing's ability to contain at least 115% of the well's maximum allowable operating pressure.

Step 5a: The operator will conduct a **Cement Bond Log** for the well.

The Cement Bond Log is a sonic test that measures the adherence between cement and the external casing of the well, and also the contact between the cement anchor of the well and the underground gas reservoir. Cement should be solidly bonded to both the well's external casing and the geologic formation to ensure a seal that prevents fluids or gases from migrating up or down the outside of the well. The interior metal tubing for the entire well must be pulled to conduct this test. A passing test for a cement bond log shows no significant spaces between cement and casing, or between cement and the gas storage formation and cap rock.

Step 6a: The operator will conduct a **Multi-Arm Caliper Inspection** of the well.

This Inspection measures any internal degradation or significant changes to the well's geometry. In this inspection, metallic sensors or "arms" radiate out from a central wire that runs down the inside of the well's exterior casing to measure the shape of the casing. If the inspection reveals a thinning or deformity of the casing, the current strength of the casing will be calculated. If the current strength of the casing has diminished, such that it cannot withstand authorized operating pressures plus a built-in safety factor of additional pressure, the well fails this inspection. A passing test for a Multi-Arm Caliper Inspection would show no deformation or thinning of the casing that diminishes the casing from being able to properly contain at least 115% of each well's maximum operating pressure.

Step 7a: The operator will conduct a **Pressure Test** of the well.

Pressure tests increase the pressure within the interior metal tubing of the well, and in the annular space between this interior tubing and the well's outer casing, to determine the well's ability to withstand normal operating pressures. The interior tubing is isolated and then pressure tested. Next the annular space between tubing and casing is pressure tested. This testing also evaluates

the integrity of any packers, which seal the annular space between the tubing and casing. A passing test for a pressure test would show a minimum pressure loss when the pressure is raised to a level of 115% of the maximum operating pressure.

After conducting the above tests, the operator will conduct any indicated remediation so that the well can pass these tests. For instance, if a test indicates casing degradation, the operator could install a metal sleeve inside the casing, with cement between the sleeve and casing. The well would then be required to undergo the tests once again to demonstrate well integrity. Any remediation will be subject to the review of Division engineers.

If the well passes the Casing Wall Thickness Inspection, the Cement Bond Log, the Multi-Arm Caliper Extension and the Pressure Test, the Division may approve the well for upcoming gas injections and withdrawal. As noted below, wells approved for operation will only be permitted to inject or withdraw gas through the interior tubing.

Required Actions if the Well is Intended to be Taken Out of Operation and Isolated from the Formation:

Step 4b: Confirm the presence of cement outside the well's external casing in the section of the well that prevents the movement of gas from the underground gas reservoir to shallower geologic zones above the reservoir. Existing cement bond logs and well construction records provide this information. This confirmation requires compliance with Division regulations and concurrence of Division engineers.

Step 5b: Install a mechanical seal or "packer" within the well's external casing and install a mechanical plug within the well's interior metal tubing, if applicable. These seals will be set in place near the bottom of the well, within the portion of the well surrounded by cement. This kind of seal is an industry standard practice for isolating a well from reservoir gases or fluids and will further protect the casing from internal gas pressure. **Step 6b**: Fill the well with fluid to the well's surface in order to create appropriate downward pressure in the well that further contributes to the integrity of the well seal.

These measures will isolate a well from the underground gas reservoir, as confirmed by National Labs experts. Each of the above actions is subject to review and approval by Division Engineers.

Step 7b: Once the operator has completed steps 4b, 5b, and 6b, and the seal is in place at the bottom of the well and the well is filled with fluid above the seal, the operator shall:

c. Conduct daily gas monitoring at the surface of the non-operational well, including monitoring the area around the well perimeter and in the annular space between the plugged casing string and the outmost casing.
d. Install and operate real-time pressure monitors that provide immediate notification to the operator when pressures deviate from normal in the well's interior tubing and its annular space.
e. Conduct noise log, temperature log and positive pressure test every 6 months.

The above monitoring shall be reported to Division engineers and maintained as a part of the well file. Division engineers will review all submitted information for evaluation on a regular basis to ensure that the well taken out of service has maintained safety.

Any well taken out of operation cannot be approved to resume operations and gas injection until the successful completion of the battery of tests described above in 4a–7a (Casing Wall

Thickness Inspection, the Cement Bond Log, the Multi-Arm Caliper Extension and the Pressure Test) is completed. Those tests must be completed within a year of the well being taken out of operation. If a well cannot successfully complete all necessary steps required in this safety review after one year of being removed from normal operations, the well shall be permanently taken out of service.

REQUIREMENTS FOR WELLS RESUMING OPERATIONS IN ALISO CANYON

In order for gas injections to resume in the Aliso Canyon Storage Facility, the Division Supervisor must confirm in writing that all wells in the facility have either completed and passed the full battery of tests required in the safety review or have been taken out of service and isolated from the underground gas reservoir.

At whatever future point reinjection is allowed to occur, under Order of the Supervisor, all wells that are allowed to inject gas into the Aliso Canyon facility will now be required to:

1. Install and operate real-time pressure monitors that provide immediate notification to the operator when pressures deviate from normal in the well's interior tubing and its annular space.
2. Operate with lowest possible operating pressure on the tubing-casing annulus.
3. Inject and withdrawal only through interior metal tubing; under no circumstances will dual (tubing and casing) injection and withdrawal be approved for any wells.
4. Undergo testing of any downhole devices (e.g., valves, diverters) after the device has been installed and prior to the well resuming operation.
5. Undergo testing of any downhole devices every 6 months.
6. Comply with of the state's Underground Injection Control regulations.
7. Establish a facility-wide emergency response plan and a safety and spill prevention plan.