Ex. I - 1

DATA RESPONSE TO SOUTHERN CALIFORNIA GAS COMPANY IN I.19-06-016:

1. Identify the sponsoring witness(es) for SED's OPENING TESTIMONY.

The sponsoring witness for SED's opening testimony is Ms. Margaret Felts.

Ex. I - 2

An official website of the United States government Here's how you know

United States Department of Transportation

Pipeline Technical Resources
UNGS Overview
UNGS Key Documents
UNGS Locations
UNGS Major Incidents
UNGS Pictures
UNGS State Participation
UNGS Technical Reports

Related Links

- UNGS IFR
- UNGS IFR (PDF)
- Full Interagency Task Force Final Report "Ensuring safe and relaible Undergroun...
- DOE Fact Sheet on Interagency Task Force Recommendations
- 49 CFR Part 192
- UNGS FAQs
- Pipeline Safety: Safety of Underground Natural Gas Storage Facilities; Petition...

Contact Us

U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration
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Business Hours: 9:00am-5:00pm ET, M-F

Underground Natural Gas Storage

This site is administered by the Pipeline and Hazardous Materials Safety Administration (PHMSA). It provides information concerning Safe Operations of Underground Gas Storage Facilities for Natural Gas.

Interim Final Rule

On December 19, 2016, PHMSA published in the Federal Register an interim final rule (IFR) that revises the Federal pipeline safety regulations to address critical safety issues related to downhole facilities, including wells, wellbore tubing, and casing, at underground natural gas storage facilities. This IFR responds to Section 12 of the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016, which was enacted following the serious natural gas leak at the Aliso Canyon facility in California on October 23, 2015. This IFR incorporates by reference two American Petroleum Institute (API) Recommended Practices (RP): (1) API RP 1170, "Design and Operation of Solution-mined Salt Caverns used for Natural Gas Storage," issued in July 2015, and (2) API RP 1171, "Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs," issued in September 2015.

Gas Leak at Aliso Canyon Underground Natural Gas Storage Facility

On October 23, 2015, a massive gas leak occurred at the Aliso Canyon Underground Natural Gas Storage Facility near Los Angeles, California. In the wake of that incident, an interagency task force was established that consisted of representatives from the Department of Energy (DOE), Department of Transportation (DOT), the Environmental Protection Agency (EPA), the Federal Energy Regulatory Commission (FERC), the Department of Commerce (DOC), the Department of Health and Human Services (HHS), and the Department of the Interior (DOI), and from state and local governments. The Task Force included premier scientists, engineers and technical experts from across the DOE complex, including five National Labs, the other Federal departments, and the Executive Office of the President.

The Task Force issued a report in October 2016 intended to help reduce the risk of future similar incidents.

Advisory Bulletin ADB-2016-02

On February 11, 2016, in response to the Aliso Canyon Underground Natural Gas Storage Facility incident, PHMSA issued Advisory Bulletin ADB-2016-02 to owners and operators of underground pipeline and storage facilities regarding the safe operation of underground storage facilities for natural gas [Docket No. PHMSA-2016-0016].

The bulletin was issued to remind all owners and operators of underground storage facilities used for the storage of natural gas, as defined in 49 CFR part 192, to consider the overall integrity of the facilities to ensure the safety of the public and operating personnel and to protect the environment. The bulletin was intended to inform operators about recommended practices and to urge operators to take all necessary actions, including but not limited to those set forth in the bulletin, to prevent and mitigate breach of integrity, leaks, or failures at their underground storage facilities and to ensure the safety of the public and operating personnel and to protect the environment. Operators should have comprehensive and up-to-date processes, procedures, mitigation measures, periodic assessments and reassessments, and emergency plans in place to maintain the safety and integrity of all underground storage wells and associated facilities whether operating, idled, or plugged. Operators must adhere to applicable State regulations for the permitting, drilling, completion, and operation of storage wells.

All owners and operators of underground storage facilities used for the storage of natural gas, as defined in 49 CFR part 192, should review their operating, maintenance, and emergency response activities to ensure properly and adequately the overall integrity of the facilities. Operators should identify the potential of

facility leaks and failures caused by corrosion, chemical damage, mechanical damage, or other material deficiencies in piping, tubing, casing, valves, and associated facilities. Operators must also consider the importance of reviewing the location and operations of shut-off and isolation systems and reviewing and updating emergency plans as necessary.

PIPES Act of 2016

On June 22, 2016, the PIPES Act of 2016 was enacted (Public Law No. 114-183). With regard to Underground Gas Storage Facilities, the PIPES Act of 2016 (the Act) amends 49 U.S.C. section 60101(a) to define "underground natural gas storage facility" as "a gas pipeline facility that stores natural gas in an underground facility, including—(A) a depleted hydrocarbon reservoir; (B) an aquifer reservoir; or (C) a solution-mined salt cavern reservoir." The Act requires PHMSA to issue, within two years of passage, "minimum safety standards for underground natural gas storage facilities." In addition, the Act expressly allows states to adopt more stringent safety standards for intrastate facilities, if such standards are compatible with the minimum standards prescribed in section 12 of the Act. In order to implement the safety standards, the PIPES Act imposes a "user fee" on entities operating underground storage facilities.

Additional Information

- May 2019 presentation to American Gas Association
- August 2018 presentation to Southern Gas Association
- February 2018 presentation to the Louisiana Mid-Continent Oil & Gas Association.

Menu links on the left of this page provide additional information regarding the safe operation of underground natural gas storage facilities. This site will be updated as new information becomes available.

Related Links

- PHMSA Underground Natural Gas Storage IA Question Set
- UNGS IFR
- UNGS IFR (PDF)
- Full Interagency Task Force Final Report "Ensuring safe and relaible Underground Natural Gas Storage"
- DOE Fact Sheet on Interagency Task Force Recommendations
- 49 CFR Part 192
- UNGS FAQs
- Pipeline Safety: Safety of Underground Natural Gas Storage Facilities; Petition for Reconsideration (PDF)
- Pipeline Safety Underground Natural Gas Storage Grants

Last updated: Thursday, February 27, 2020

U.S. DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

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Ex. I - 3

DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

49 CFR Parts 191, 192, and 195

[Docket No. PHMSA–2016–0016; Amdt. Nos. 191–27; 192–126; 195–103]

RIN 2137–AF22

Pipeline Safety: Safety of Underground Natural Gas Storage Facilities

AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA), Department of Transportation (DOT).

ACTION: Final rule.

SUMMARY: The Pipeline and Hazardous Materials Safety Administration is publishing this final rule to amend its minimum safety standards for underground natural gas storage facilities (UNGSFs). On December 19, 2016, PHMSA issued an interim final rule (IFR) establishing regulations in response to the 2015 Aliso Canyon incident and the subsequent mandate in section 12 of the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016. The IFR incorporated by reference two American Petroleum Institute (API) Recommended Practices (RPs): API RP 1170, ''Design and Operation of Solution-mined Salt Caverns Used for Natural Gas Storage'' (First Edition, July 2015); and API RP 1171, ''Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs'' (First Edition, September 2015). The IFR required each provision in the API RPs to apply as mandatory (*i.e.,* each ''should'' statement would apply as a ''shall'') unless an operator provides written justification for not implementing the practice, including an explanation for why it is impracticable and not necessary for safety. Based on the comments received to the IFR and a petition for reconsideration, PHMSA has determined that the RPs, as originally published, will provide PHMSA with a stronger basis upon which to base enforcement than the IFR. This final rule also addresses recommendations from commenters and a petition for reconsideration of the IFR by modifying compliance timelines, revising the definition of a UNGSF, clarifying the states' regulatory role, reducing recordkeeping and reporting requirements, formalizing integrity management practices, and adding risk management requirements for solution-mined salt caverns.

DATES: This final rule is effective on March 13, 2020. The Director of the Federal Register approved the incorporation by reference on January 18, 2017.

FOR FURTHER INFORMATION CONTACT:

Technical questions: Byron Coy, Senior Technical Advisor, by telephone at 609–771–7810 or by email at *byron.coy@dot.gov.*

General information: Ashlin Bollacker, Technical Writer, by telephone at 202–366–4203 or by email at *ashlin.bollacker@dot.gov.*

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IV. Regulatory Analyses and Notices

I. Executive Summary

A. Purpose of This Final Rule

The Pipeline and Hazardous Materials Safety Administration (PHMSA) is amending the pipeline safety regulations applicable to underground natural gas storage facilities (UNGSFs). PHMSA is amending the UNGSF regulations in response to comments and recommendations received on its interim final rule (IFR) published on December 19, 2016 (81 FR 91860). The IFR implemented PHMSA's authority to regulate UNGSFs and the Congressional mandate in section 12 of the PIPES Act (Pub. L. 114–183) to establish minimum safety standards for depleted-hydrocarbon reservoirs, aquifer reservoirs, and solution-mined salt caverns used for the storage of natural gas.[1] Congress issued the mandate to PHMSA following a large-scale natural gas leak at the Aliso Canyon UNGSF in Southern California on October 23, 2015. The mandate required PHMSA to establish minimum safety standards for UNGSFs within two years of the PIPES Act issuance on June 22, 2016. To meet the mandate's deadline—and address the urgent need for safer storage of natural gas—PHMSA published the IFR with a 60-day comment period. The IFR went into effect on January 18, 2017.

Since that time, PHMSA has considered public comments and a petition for reconsideration of the IFR and is modifying the minimum safety standards for UNGSFs in this final rule accordingly. PHMSA has also further reviewed the Final Report of the Interagency Task Force on Natural Gas Storage Safety[2] to ensure any amendments in this final rule are consistent with the Task Force's recommendations to PHMSA.[3] As detailed in this final rule, PHMSA believes these changes will reduce regulatory burdens and reduce costs for industry and gas consumers while sustaining safety and protecting the environment.

B. Summary of the Major Provisions

Consistent with the IFR, this final rule maintains the incorporation by reference of American Petroleum Institute (API) Recommended Practices (RPs) 1170 and 1171 (the RPs) as the basis of the minimum safety standards in 49 CFR part 192. API RP 1170, ''Design and Operation of Solution-mined Salt Caverns Used for Natural Gas Storage''[4] has recommended practices for solution-mined salt cavern facilities used for natural gas storage and covers facility geomechanical assessments, cavern well design and drilling, solution mining techniques,

[1] For a description of these storage types and other basic information about underground natural gas storage, see *https://www.eia.gov/naturalgas/storage/basics/.*

[2] ''Ensuring Safe and Reliable Underground Natural Gas Storage,'' Final Report of the Interagency Task force on Natural Gas Storage Safety; October 2016. See *https://www.energy.gov/downloads/report-ensuring-safe-and-reliable-underground-natural-gas-storage.*

[3] In addition to their comments on the IFR, on March 17, 2017, the State of Texas and the Texas Railroad Commission petitioned the U.S. Court of Appeals for the Fifth Circuit for review of the IFR under 49 U.S.C. 60119(a). *See State of Texas* v. *PHMSA,* No. 17–60189 (5th Cir. Mar. 17, 2017). On April 24, 2017, the court granted INGAA and AGA's motions to intervene in the litigation. On July 19, 2017, the court granted a joint motion to hold the petition for review in abeyance pending the issuance of this final rule.

[4] API Recommended Practice 1170 ''Design and Operation of Solution-mined Salt Caverns used for Natural Gas Storage (First Edition, July 2015).

and operations, including monitoring and maintenance practices. API RP 1171, ''Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs'' [5] has recommended practices for natural gas storage in depleted oil and gas reservoirs and aquifers, and focuses on storage well, reservoir, and fluid management for functional integrity in design, construction, operation, monitoring, maintenance, and documentation practices. Both RPs describe ways to maintain the functional integrity of design, construction, operation, monitoring, maintenance, and documentation practices for UNGSFs. The RPs contain numerous provisions that use the term ''shall'' to denote a minimum requirement necessary to comply with the RP. The RPs also use non-mandatory terms such as ''should,'' ''may,'' and ''can'' to denote a recommendation that is advised, but not required.

This final rule amends the IFR in six primary ways. First, PHMSA adopts the RPs without modification to the non-mandatory terms. In the IFR, PHMSA adopted the RPs by modifying the non-mandatory provisions (*i.e.,* statements containing ''should'' and other non-mandatory terms) as mandatory requirements (*i.e.,* ''shall''). PHMSA provided that operators could deviate from the modified statements by providing a justification in their procedure manuals as to why the provision was ''not practicable and not necessary for safety'' at their specific facility. Accordingly, with this final rule, PHMSA also no longer requires operators to provide written justifications as to why they would not have performed a ''should'' provision.

Second, this final rule is formalizing requirements and deadlines for operators to develop and implement their integrity management (IM) programs and to conduct their baseline risk assessments for UNGSFs. As noted by commenters and petitioners, the API RPs function as an IM system for UNGSFs, which requires more time to implement than the IFR allowed. After considering these comments and recommendations, PHMSA is relaxing the timeline for completing initial assessments of the reservoirs, caverns, and wells. PHMSA discusses these new requirements and deadlines in Section III–C, ''Compliance Timelines.''

Third, this final rule includes a requirement for solution-mined salt caverns to follow the same risk management practices as depleted-hydrocarbon reservoirs and aquifers that apply to the physical characteristics and operations of the facility (*i.e.,* follow section 8 of API RP 1171). Since the publication of the IFR, PHMSA has observed that many operators of solution-mined salt caverns are voluntarily using section 8 of API RP 1171 to supplement the risk management practices in section 10 of API RP 1170. While most salt-cavern UNGSFs have a risk-management program in place, section 8 of API RP 1171 provides more prescriptive practices than API RP 1170 for how an operator must develop, implement, and document a program to manage risks that could affect the functional integrity of the storage operation. Extending the applicability of the recommended practices in section 8 of 1171 closes a potential critical safety gap for salt-cavern storage facilities and may prevent future failures at these facilities. PHMSA has codified this practice in the final rule to ensure consistency across all UNGSF facilities.

Fourth, PHMSA is narrowing the scope of reportable events and changes at facilities. In addition to annual data reporting and National Registry information, the IFR required operators to notify PHMSA of certain changes and events and their facilities, such as incidents and safety-related conditions. Since the IFR, PHMSA received many notifications for routine maintenance activities, which was not the intent of the regulation. Operators are not required to notify PHMSA of regular maintenance. To make this clear, PHMSA is limiting notification of changes to a facility 60 days prior to the following events: (1) All plugging or abandonment activities (regardless of costs), and (2) construction or maintenance that requires a workover rig and costs $200,000 or more. PHMSA is also applying an emergency exemption to the 60-day notification requirements, which PHMSA overlooked in the IFR.

Fifth, this final rule is revising the definition of an ''underground natural gas storage facility.'' The PIPES Act amended 49 U.S.C. 60101(a) to define an ''underground natural gas storage facility'' as ''a gas pipeline facility that stores natural gas in an underground facility, including—a depleted hydrocarbon reservoir, an aquifer reservoir; or a solution-mined salt cavern reservoir.'' The IFR incorporated a modified version of this definition in part 192. Part 192 covers the transportation of natural gas by pipeline. PHMSA discovered through the public comments on the IFR that the placement of the definition in part 192 created questions for operators as to where a gas pipeline facility ended, and regulations for a UNGSFs began. To remedy this confusion, PHMSA is revising the definition of an ''underground natural gas storage facility'' to exclude other components of a gas pipeline or gas pipeline facility covered elsewhere in part 192, and eliminate any potential overlap. PHMSA discusses the revised definition and the reason for keeping it in part 192 later in this document.

Sixth, PHMSA is changing the name of the reporting portal to the ''National Registry of Operators'' (formerly the ''National Registry of Pipeline and LNG Operators''). Additionally, PHMSA is revising the name of the online portal's web address from ''*http://opsweb.phmsa.dot.gov*'' to ''*https://portal.phmsa.dot.gov*.'' These changes are throughout parts 191, 192, and 195.

C. Costs and Benefits

Consistent with Executive Order (E.O.) 12866, PHMSA has prepared a Regulatory Impact Analysis (RIA) that includes an assessment of the benefits and costs of this final rule, as well as reasonable alternatives. PHMSA published an RIA to accompany the IFR as well. This final RIA incorporates input from public comments on the IFR and the initial RIA. PHMSA has issued the final RIA concurrently with this final rule, and it is available in the docket (PHMSA–2016–0016).

The annualized cost savings for this final rule, relative to the IFR, are estimated to be $11 million, applying a 7 percent discount rate. The benefits of this final rule come from making permanent the safety measures in the IFR and RPs 1170 and 1171, which API and other stakeholders developed to prevent leaks and blowouts before they occur. The safety measures adopted through the IFR and this final rule will prompt operators to undertake or hasten preventive and mitigative measures, as well as IM actions, such as mechanical integrity tests, that will reduce the probability of releases.

The IFR reduced the likelihood and magnitude of catastrophic or operational natural gas releases by promoting safer practices through the incorporation of the recommended practices into the pipeline safety regulations. This final rule continues to require these same practices. For example, operators are required to assess the mechanical integrity of each storage well, evaluate the likelihood of failures at these wells, and determine the next steps to remedy conditions that could precede the

[5] API Recommended Practice 1170 ''Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs'' (First Edition, September 2015).

failures. Operators are also required to incorporate safety best practices when designing and constructing new wells, which could further prevent catastrophic failures.

This final rule also adds a requirement for all solution-mined salt caverns to follow the risk management practices in section 8 of RP 1171. Per the IFR, PHMSA had only required operators of solution-mined salt caverns to follow the risk management practices in section 10 of RP 1170. The language in section 10, requires operators to take a ''holistic and comprehensive approach to monitoring cavern integrity,'' without providing specifics as to how to implement that approach. Post-IFR, during preliminary inspections, PHMSA observed operators of solution-mined salt caverns applying the framework of the risk management practices in section 8 of RP 1171. While RP 1171 applies to depleted hydrocarbon reservoirs and aquifer reservoirs, it offers a framework for risk management and monitoring that is translatable to other types of underground storage facilities. PHMSA expects that other operators of solution-mined salt caverns would benefit from a more specific framework for implementing the ''holistic and comprehensive approach to monitoring cavern integrity'' required in section 10 of 1170.

Additionally, codifying the requirement for these operators to follow both section 8 of RP 1171 and section 10 of RP 1170 ensures consistent safety requirements across all UGS facilities. This change may cause those operators who were not already (voluntarily) applying API RP 1171 as a framework for monitoring cavern integrity to undertake stronger risk management practices, which could ultimately reduce the risk of an incident. However, PHMSA considers this action part of the baseline requirements to follow a ''holistic and comprehensive approach to monitoring cavern integrity'' already prescribed through the IFR. As a result, PHMSA does not expect an additional financial burden to operators beyond that already in place through the IFR.

The IFR required operators to provide a written justification for each non-mandatory provision of the RPs that they did not perform. This final rule removes that recordkeeping burden on operators. Operators experience cost savings from the removal of requirements associated with deviations from the RPs, including technical reviews by subject matter experts and recordkeeping burdens, and reductions in the notifications burden.

II. Background

A. Overview of Underground Natural Gas Storage

Underground storage of natural gas plays a critical role in the nation's energy independence and reliability. Notably, having a surplus of natural gas provides a buffer from the seasonal variations in supply and demand, creating price stability for customers. Over the past ten years, natural gas storage has increased 16 percent, prompted, in part, by significant growth in domestic shale-gas production.

There are three principal types of underground natural gas storage fields, each with different geological characteristics and capabilities that govern their suitability for storage. The three types are depleted hydrocarbon reservoirs, aquifer reservoirs, and solution-mined salt caverns. Depleted hydrocarbon reservoirs are the most common type of storage, representing approximately 80 percent of the total working gas capacity in the United States. As the name implies, these facilities are repurposed from previous oil or gas production and converted to gas storage fields.[6] Aquifer reservoirs are natural water-bearing formations, also converted to gas storage, and represent roughly 9 percent of the total working gas capacity in the United States. Solution-mined salt caverns (salt domes) are geological formations that leached out of salt deposits. These facilities represent only about 10 percent of the total working-gas capacity but provide high withdrawal and injection rates relative to their working gas capacity.[7]

Of the 403 active UNGSFs in the United States, approximately 60 percent of the facilities are interstate, and 40 percent of the facilities are intrastate.[8] The total storage capacity at these fields was 9,236 billion cubic feet (Bcf), and the total working gas capacity was 4,815 Bcf. Facilities identified as interstate represented 63 percent of total storage capacity and 65 percent of working gas capacity.

Interstate UNGSFs serve interstate facilities, such as providing storage for interstate gas transmission pipelines.[9] These types of storage facilities commonly receive surplus gas from interstate pipelines during warmer months and then send it back into the product stream during colder winter months. Since these UNGSFs serve interstate facilities and PHMSA has exclusive pipeline safety jurisdiction over the design, construction, operation, and maintenance of interstate gas pipeline facilities, the standards in this final rule will affect all interstate UNGSFs.

Intrastate UNGSFs, on the other hand, are facilities that provide gas storage for intrastate pipelines, most notably local gas distribution companies (LDCs). These storage facilities serve intrastate pipelines that are contained entirely within a particular State and that do not fall within the jurisdiction of the Federal Energy Regulatory Commission (FERC). As discussed more fully below, these intrastate ''gas pipeline facilities'' are generally subject to the IFR and this final rule. Intrastate UNGSFs may continue to also be subject to State regulations provided that: (a) The otherwise applicable State regulation does not conflict with the Federal minimum safety standards established in the final rule, and (b) the applicable State authority has filed a certification with PHMSA to participate as a full State partner under the new Federal program and to receive Federal funding through PHMSA.

B. Underground Storage Incidents and Regulatory History

While rare, serious incidents at underground storage facilities have occurred. For instance, on April 7, 1992, an uncontrolled release of highly volatile liquids from a salt-dome storage cavern near Brenham, Texas, formed a heavier-than-air gas cloud that exploded. Three people died in the accident, with an additional 21 people treated for injuries at area hospitals. Property damage from the accident exceeded $9 million.

Following its accident investigation, the National Transportation Safety Board (NTSB) published pipeline safety recommendation No. P–93–9 regarding underground storage. Recommendation P–93–9 asked PHMSA's predecessor agency, the Research and Special Programs Administration (RSPA), to develop safety requirements for storage of highly volatile liquids and natural gas

[6] Energy Information Administration (EIA). 2015. ''The Basics of Underground Natural Gas Storage.'' November 16, 2015. Retrieved from *http://www.eia.gov/naturalgas/storage/basics/* (Accessed March 2019).

[7] Total working gas capacity percentages do not sum to 100 percent due to rounding.

[8] PHMSA's 2018 annual report data show 403 active underground natural gas storage fields in the United States as of 2017, distributed across 31 states.

[9] Under 49 U.S.C. 60101(a)(6), an ''interstate gas pipeline facility'' (including an interstate UNGSF) is defined as ''a gas pipeline facility—(A) used to transport gas; and (B) subject to the jurisdiction of the [FERC] under the Natural Gas Act (15 U.S.C. 717 *et seq.*).'' The term ''transporting gas'' is defined in § 60101(a)(21) as ''the gathering, transmission, or distribution of gas by pipeline, or the storage of gas, in interstate or foreign commerce . . .''

in underground facilities, including a requirement that all pipeline operators perform safety analyses of new and existing underground geologic storage systems to identify potential failures, determine the likelihood that each failure will occur, and assess the feasibility of reducing the risk.[10]

In response to the NTSB's safety recommendation, RSPA held a public meeting [11] to determine what actions it should take, if any, regarding the regulation of underground storage of natural gas and hazardous liquids. The participants expressed mixed views on whether RSPA should begin to regulate ''downhole'' pipe and underground storage. Most participants spoke favorably of industry safety practices and State regulation but saw no immediate need for Federal regulatory action.

On July 1, 1997, RPSA issued an advisory bulletin (ADB–97–04) to inform UNGSF owners and operators of the availability of guidelines for the design and operation of underground storage facilities. Specifically, the advisory bulletin pointed to the safety standards guide from the Interstate Oil and Gas Compact Commission (IOGCC) [12] and API as appropriate for use by pipeline operators and State regulatory agencies. The IOGCC guide provided safety standards for the design, construction, and operation of gas storage caverns. API had published guidelines for the underground storage of liquid hydrocarbons. RP 1114, ''Design of Solution-Mined Underground Storage Facilities,'' June 1994, provided basic guidance on the design and development of new solution-mined underground storage facilities. RP 1115, ''Operation of Solution-Mined Underground Storage Facilities,'' September 1994, provided guidance on the operation of solution-mined underground hydrocarbon liquid or liquefied petroleum gas storage facilities.

Another catastrophic natural gas leak happened in January 2001 after a wellbore failed at the Yaggy storage field near Hutchinson, Kansas. The natural gas migrated nine miles underground, where it eventually surfaced through abandoned wells. Once at the surface, the natural gas exploded, killing two people and destroying two businesses.[13] After a month, the flares burned off, with the ultimate loss of 143 million cubic feet (MCF) of natural gas from the storage field.

These incidents at UNGSFs alerted operators and regulators to consider assessing the safety of these facilities. By 2012, API had begun developing additional guidance for the safety of UNGSFs. API developed RP 1170 and 1171 over several years, based on input from many industry stakeholders, including regulators such as PHMSA, FERC, and five State regulatory agencies, as well as the API Midstream Group. In July 2015, API issued RP 1170, ''Design and Operation of Solution-mined Salt Caverns Used for Natural Gas Storage.'' API RP 1170 provides recommendations and requirements for geo-mechanical assessments, cavern well design and drilling, solution mining techniques, operations and maintenance procedures, and practices for salt caverns. In September 2015, API issued RP 1171, ''Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs,'' which focuses on storage well, reservoir, and fluid management for functional integrity in design, construction, operations and maintenance procedures, monitoring, and documentation practices. The RPs appropriately recognize the variety and diversity of UNGSFs used throughout the United States and are not limited to addressing facilities in a single State, basin, geological setting, or well type.

C. Aliso Canyon Incident

Shortly after the publication of the industry safety standards RP 1170 and RP 1171, another major UNGSF incident occurred. On October 23, 2015, Southern California Gas Company (SoCalGas) discovered a leak that manifested into the largest methane leak from a natural gas storage facility in U.S. history. Well SS–25 in the Aliso Canyon storage field, located in Los Angeles County, California, leaked for nearly four months until it was permanently sealed on February 17, 2016. While SoCalGas attempted to plug the leak, residents in nearby neighborhoods experienced health symptoms consistent with exposure to the odorants (mercaptans) added to natural gas and residual components from previous oil production in the field. The incident temporarily displaced more than 5,000 households from their homes, according to the Aliso Canyon Incident Command briefing report issued on February 1, 2016, although some sources place the number of related households at approximately 8,000.[14]

The leak at Aliso Canyon ultimately released approximately 5.7 Bcf of natural gas into the atmosphere, translating to 109,000 metric tons [15] of methane, a potent greenhouse gas, as well as numerous other pollutants.[16] Additional reports identified other potential health effects that lasted even after the well was sealed. A report by the Los Angeles County of Public Health suggests that the continued health symptoms may be due to contaminants in indoor air and dust.[17] As of December 31, 2016, SoCalGas and its parent company, Sempra Energy, recorded estimated costs of $913 million to control the release, monitor air emissions, relocate residents, and cover legal and other expenses.[18] The singular well that failed in the Aliso Canyon accident (SS–25) had originally been drilled in 1953 and was re-purposed for natural gas storage in 1972. The age of this well is not unusual. Per data from the American Gas Association (AGA), approximately 60 percent of active storage wells are located in fields that were activated before 1960.

The Aliso Canyon incident created serious energy-supply challenges for the region and prompted public concerns about the safety of UNGSFs, including the extent and effectiveness of Federal and State oversight. On February 5, 2016, PHMSA issued an advisory bulletin (ABD–2016–02), identifying specific minimum actions that operators of UNGSFs should take, in addition to the recommendations of ADB–97–04,

[10] National Transportation Safety Board, Pipeline Accident Report PAR–93/01 (Nov. 4, 1993).

[11] (Docket PS–137, 59 FR 30567, June 14, 1994).

[12] Interstate Oil and Gas Compact Commission, ''Natural Gas Storage in Salt Caverns: A Guide for State Regulators.'' (IOGCC Guide), 1995.

[13] Allison, M. Lee, 2001, The Hutchinson Gas Explosions: Unraveling a Geologic Mystery, Kansas Bar Association, 26th Annual KBA/KIOGA Oil and Gas Law Conference, v1, p3–1 to 3–29.

[14] For example, see KPCC news report on August 4, 2016, ''Cost estimate of Aliso Canyon gas leak hits $717 million''. *http://www.scpr.org/news/2016/08/04/63268/cost-estimate-of-aliso-canyon-gas-leak-hits-717-mi/.*

[15] CARB estimates that the incident resulted in a total emission of 99,650 ± 9,300 metric tons of methane (CARB, 2016a) and seeks mitigation of 109,000 metric tons.

[16] California Air Resources Board (CARB), 2016; County of Los Angeles Public Health.

[17] Ibid. CARB.

[18] Of the $913 million of costs, approximately 60 percent is for the temporary relocation program (including cleaning costs and certain labor costs). Other estimated costs include amounts for efforts to control the well, stop the Leak, stop or reduce the emissions, and the estimated cost of the root cause analysis being conducted by an independent third party to investigate the cause of the Leak. The remaining portion of the $913 million includes legal costs incurred to defend litigation, the value of lost gas, the costs to mitigate the actual natural gas released, the estimated costs to settle certain actions and other costs. The value of lost gas reflects the replacement cost of volumes purchased through December 2017 and estimates for purchases in 2018. As of mid-January 2018, SoCalGas has replaced all lost gas. SoCalGas adjusts its estimated total liability associated with the Leak as additional information becomes available.'' (SoCalGas/Sempra, 2018).

API RP 1170, API RP 1171, and the IOGCC Guide. The 2016 advisory bulletin recommended that operators begin reviewing their operating, maintenance, and emergency response activities and apply the new RPs accordingly.

On July 14, 2016, PHMSA held a public meeting to discuss potentially extending its regulations to include transportation-related UNGSFs. PHMSA heard from a diverse group of stakeholders, including State regulators, emergency responders, and residents, including those impacted by the Aliso Canyon incident. PHMSA concluded that it should take action to incorporate by reference API RP 1170 and API RP 1171 into part 192. The RPs describe a range of measures that UNGSF operators should undertake to ensure the safe operations of their facilities. The RPs also include construction, maintenance, IM, security, and emergency response procedures.

D. The PIPES Act of 2016

The Aliso Canyon incident prompted broader public concerns as to how to prevent similar UNGSF accidents in the future. Congress addressed these concerns in two sections of the PIPES Act, enacted on June 22, 2016 (Pub. L. 114–183). Section 12 of the PIPES Act required PHMSA to issue minimum safety standards for all UNGSFs within two years of enactment. The statute defines an ''underground natural gas storage facility'' as a ''gas pipeline facility that stores natural gas in an underground facility.'' Because title 49 United States Code (U.S.C.) 60101(a) already defines ''gas pipeline facility'' as ''a pipeline, a right of way, a facility, a building, or equipment used in transporting gas or treating gas during its transportation,'' PHMSA interprets the PIPES Act as directing it to regulate only those UNGSFs that store natural gas incidental to transportation.

The PIPES Act requires that in issuing minimum safety standards for UNGSFs, PHMSA must: (1) Consider consensus standards for the operation, environmental protection, and integrity management of underground natural gas storage facilities; (2) consider the economic impacts of the regulations on individual gas customers; (3) ensure that the regulations do not have a significant economic impact on end users; and (4) consider the recommendations of the Aliso Canyon natural gas leak task force established under section 31 of the PIPES Act of 2016.

The Secretary of Transportation (the Secretary) delegated this responsibility under chapter 601 of title 49 U.S.C. to the PHMSA Administrator (49 CFR 1.97). PHMSA fulfilled this mandate by publishing the IFR on December 19, 2016. The PIPES Act provides that states may adopt additional or more stringent safety standards for intrastate UNGSFs if such standards are compatible with these Federal regulations.

E. Interagency Task Force

In addition to section 12 of the PIPES Act, Congress included a second mandate, section 31, directing the Department of Energy (DOE) to establish an Interagency Task Force on Natural Gas Storage Safety to perform an analysis of the Aliso Canyon events and make recommendations to reduce the occurrence of similar events in the future. PHMSA and DOE co-led the effort. The Task Force established several working groups, comprised of premier scientists, engineers, and technical experts from the Executive Office of the President and various Federal agencies. The working groups examined three key areas:

- The integrity of natural gas wells at storage facilities;
- The public health and environmental effects from natural gas leaks; and
- The nation's vulnerability to reduced energy reliability in the event of future leaks.

In October 2016, the Task Force issued its final report on natural gas storage safety and made 44 recommendations to operators and regulators. The main recommendation to PHMSA was to incorporate existing industry consensus standards, API RP 1170 and 1171, into part 192 of the regulations in an enforceable manner, and consider supplementing the regulations with recordkeeping and reporting requirements as necessary. The Task Force recommended that operators develop comprehensive risk-management plans that addressed risks based on their potential severity and probability of occurrence. These plans should document an operator's risk-management strategy, identify risks, define responsibilities among stakeholders, assess risks, and take appropriate action to reduce risks to well integrity.

The Task Force's report also highlighted growing concerns regarding the age of the nation's natural gas storage infrastructure. For example, wells reflect material, technology, and design factors that may have been appropriate at the time they were constructed, but may not meet design criteria for wells drilled today. Over time, corrosion, other environmental processes, and mechanical stresses from the injection and withdrawal of natural gas can impact well integrity. Wells in depleted oil fields may have been designed for lower operating pressures than what they may be subject to now. Many of these wells were designed without redundant barriers to reduce the risk of gas migration. One of the lessons from the Aliso Canyon incident is that wells without redundant barriers present higher risks because they have a single point of possible failure that may be extremely difficult to shut off or kill.

F. Interim Final Rule

On December 19, 2016, PHMSA issued the IFR that satisfied section 12 of the PIPES Act, exercising the agency's statutory authority to regulate underground natural gas storage facilities. The IFR amended the pipeline safety regulations found at 49 CFR parts 191 and 192, to address critical safety issues related to ''downhole'' UNGSF facilities, including wells, wellbore tubing, casing, and wellheads (81 FR 91860). Additionally, the IFR added a definition of ''underground natural gas storage facility'' to §§ 191.3 and 192.12 and applied reporting requirements to operators of UNGSFs similar to those applicable to operators of other gas pipeline facilities, including annual reports, incident reports, reports of major construction and organizational changes, and registration with the National Operator Registry.

Effective January 18, 2017, all UNGSFs, both intrastate and interstate, now had to meet the minimum standards outlined in RPs 1170 and 1171 and were subject to inspection by PHMSA or a PHMSA-certified State entity. The IFR made each provision in the RPs 1170 and 1171 mandatory unless the operator documented a technical justification why compliance with a provision was not practicable and not necessary for safety. Operators were required to incorporate the RPs into their written operations, maintenance, and emergency response program manuals following § 192.605. PHMSA, or a certified State partner, would review any of the operators' justifications and its procedure manuals during compliance inspections.

After publishing the IFR, PHMSA took significant steps to educate the regulated community on the new requirements, to promote a better understanding of issues concerning integrity assessments of UNGSFs and the implementation of the RPs. The first action was to publish frequently asked

questions (FAQs).[19] The FAQs provided guidance on the procedures, implementation plans, and schedules that operators should have in place to meet the requirements in the applicable RPs. For example, while the IFR did not provide clear timelines for operators to complete the integrity assessments required by the RPs, the FAQs provided a recommended implementation schedule. With the issuance of this final rule, PHMSA will revise the FAQ guidance material to reflect these regulations as amended.

In preparation for the development of inspection and enforcement efforts, PHMSA subject matter experts conducted preliminary site assessments at a cross-section of UNGSFs from May to July of 2017.

Additionally, PHMSA has instituted a program for training Federal and State inspectors on the new minimum Federal standards affecting all UNGSF facilities. As it promulgates this final rule, PHMSA is prepared to modify the program through future regulations and guidance to keep pace with evolving consensus safety standards, academic research, and lessons learned from the firsthand experience of its inspectors, State regulators, affected stakeholders, and the public.

G. Petition for Reconsideration

On January 18, 2017, the American Gas Association (AGA), American Petroleum Institute (API), American Public Gas Association (APGA), and Interstate Natural Gas Association of America (INGAA) (the ''Associations'') jointly filed a petition for reconsideration of the IFR. AGA represents local energy companies, as well as residential, commercial, and industrial natural gas customers. API is a national trade association representing the oil and natural gas industry, including gas pipelines and UNGSF operators. APGA is a national, non-profit association of publicly-owned natural gas distribution systems. INGAA is an industry trade association representing interstate natural gas pipeline companies in the United States.[20]

In the petition, the Associations affirmed their support for PHMSA's efforts to regulate the safety of UNGSFs. They reminded PHMSA that the Associations and their members had supported PHMSA's incorporation by reference of the RPs as Federal standards for natural gas storage. They stressed the importance of adopting the RPs to advance the safety of the pipeline transportation system but asked PHMSA to revise the IFR to incorporate RP 1170 and API RP 1171 without modification and to provide for reasonable implementation periods. The Associations stated that the changes requested in the petition would ensure that PHMSA's regulations would be practical, reasonable, and effective.

On June 20, 2017, PHMSA issued a notice stating that it would provide an answer to the petition in the final rule (82 FR 28224). PHMSA announced that in the interim, it would not issue any enforcement citations for failure to meet any of the non-mandatory provisions of the RPs that the IFR converted to mandatory ones until one year after the issuance the final rule. PHMSA has considered the recommendations from the Associations and is answering their petition in this final rule.

III. Comment Summaries and PHMSA's Responses

A. Introduction

PHMSA received 82 comments and one petition for reconsideration in response to the IFR issued on December 19, 2016. PHMSA provided a 60-day comment period initially but re-opened it on October 19, 2017 (82 FR 48655), for an additional 30 days to provide all interested parties with the opportunity to comment on the IFR and the merits and claims of the petition for reconsideration. During the initial 60-day comment period, PHMSA received 28 comments. PHMSA received 54 additional comments during the re-opened 30-day comment period, but only 14 of those 54 related to this rulemaking.[21] Half of those 14 comments were from organizations that had already submitted comments during the initial, 60-day comment period.

PHMSA discusses and responds to these comments and recommendations in sections B through J, below. For organizational purposes, PHMSA has grouped comments by subject matter. Below is a list of entities who submitted comments on the IFR.

- Atmos Energy
- Consumers Energy
- Dow Chemical Company (Dow)
- ENSTOR
- Environmental Defense Fund (EDF)
- Gas Free Seneca
- Gas Piping Technology Committee (GPTC)
- Geological Maps Foundation
- GPA Midstream Association (GPA)
- Hilcorp Alaska
- Hon. Brad Sherman, representing 30th Congressional District of California
- Independent Petroleum Association of America (IPAA)
- Joint Comment from American Gas Association (AGA), the American Petroleum Institute (API), the American Public Gas Association (APGA), and the Interstate Natural Gas Association of America (INGAA)
- Joint Comment from the States First Initiative, the Interstate Oil and Gas Compact Commission (IOGCC), and Groundwater Protection Council (GWPC)
- Louisiana Mid-Continent Oil and Gas Association (LMOGA)
- Michigan Department of Environmental Quality
- New York State Department of Environmental Conservation
- Northern Natural Gas
- Pacific Gas and Electric Company (PG&E)
- Private Citizens (50)
- Railroad Commission of Texas
- Southern California Gas Company (SoCalGas)
- Texas Pipeline Association
- TransCanada
- Vectren

B. Incorporation by Reference of API Recommended Practices 1170 and 1171

In the IFR, PHMSA required operators to treat non-mandatory language in the RPs as mandatory. For each provision modified by the IFR, an operator could deviate from the recommended practice by providing in its procedures manual a technical justification for each deviation. Under the IFR, PHMSA required an operator to use a subject matter expert to review and document the technical justification, and a member of the operator's executive leadership was required to review, approve, and document the date of approval. During routine inspections, PHMSA would review an operator's justifications for deviating from the modified provisions.

1. Comments on PHMSA's Modification of the RPs

Many commenters disagreed with PHMSA's modification of the non-mandatory provisions of the RPs. Almost all commenters supported the Associations' position concerning the

[19] ''Underground Natural Gas Storage: FAQs.'' (revised April 2017) *https://primis.phmsa.dot.gov/ung/faqs.htm.*

[20] On April 17, 2017, INGAA withdrew from the petition for reconsideration, but the other three Associations have remained as petitioners.

[21] The 40 comments that PHMSA deemed not relevant appear to have been submitted anonymously using automated technology (*i.e.,* bots). While these comments raise generalized issues related to environmental protection (climate change, renewable/alternative energy, streamlining environmental reviews, etc.), the comments do not connect their generalized statements to any of the specific provisions of this rulemaking, such that they would become meaningful to the issue of the safety of underground natural gas storage systems.

conversion of the non-mandatory provisions in RPs 1170 and 1171 to mandatory. Generally, commenters supported the need for consistent minimum safety standards for all UNGSFs and supported regulations to that effect. Those same commenters asserted that if PHMSA adopted the IFR without modification, it would impose burdensome and impracticable requirements on operators.

In their petition, the Associations stated that ''changing the [RPs] in this manner is not necessary for enforcement, nor is it practicable or reasonable.'' The Associations stated their belief that there was ''no regulatory justification for making all 'non-mandatory' provisions 'mandatory,' '' and requested that PHMSA eliminate this provision. Further, the Associations said that although the RPs use both non-mandatory and mandatory language, this alone does not affect their enforceability. They said that the RPs contain enough mandatory provisions to ensure enforceability. The Associations used the mandatory provisions in section 8 to demonstrate that the RPs are broad enough, as written, to be enforced. Additionally, they stated that the non-mandatory statements in the RPs do not compromise the enforceability of the broad requirements imposed on operators through the mandatory provisions.

The Texas RRC stated that it strongly disagreed with PHMSA's modification of the RPs. The Texas RRC noted that the wholesale adoption of RPs would lead to confusion and have unintended consequences. It said that if PHMSA kept the modification to the non-mandatory provisions in the final rule, it would undermine the integrity of the original RPs, ultimately making them even more difficult to enforce. Lastly, the Texas RRC stated that, while the IFR allowed an operator to deviate from particular provisions, PHMSA did not provide a process or timeframe by which the agency would review, approve, or deny the operator's alternative procedure(s). The Texas RRC requested that, if PHMSA chose to incorporate the RPs as modified by the IFR, the agency should add a review process and timeline for consideration of requests for deviation from the modified provisions.

ENSTOR Operating Company, LLC (ENSTOR), asserted that converting all non-mandatory provisions in the RPs to mandatory requirements would undermine the risk-based approach of the RPs and create unintended results. ENSTOR stated that PHMSA's conversion of non-mandatory RP statements in sections 8, 9, 10, and 11 of RP 1171 to mandatory provisions could establish statutorily-impermissible retroactive requirements, such as requiring the use of observation wells drilled around, above, and below a reservoir. ENSTOR added that PHMSA ''can simply require operators to discontinue any deviations that the agency does not agree with,'' and ''there are no standards to guide the agency's determination and no means for review or appeal of a denial of an operator deviation.''

Some operators stated that the process for justifying deviations from a specific non-mandatory RP would be time-intensive, expensive, and unworkable for many operators. LMOGA stated that requiring technical documentation for each deviation was excessive since the RPs themselves already identified the non-mandatory practices as applicable on a case-by-case and site-specific basis. Further, LMOGA noted that the IFR required each deviation must be ''technically reviewed and documented by a subject matter expert to ensure that there will be no adverse impact on the facility. . . .'' LMOGA argued that the term ''subject matter expert'' was vague and imprecise.

EDF said that PHMSA would not be reviewing an operator's technical justifications until after the operator had already deviated from a recommended practice and contended that this could allow harmful activities to persist until an inspection took place at the facility. Further, EDF said that operators might make significant financial commitments in reliance on unapproved deviations, only to see their decisions overturned after the fact, without practical recourse, by PHMSA. Regarding the IFR's treatment of non-mandatory provisions as mandatory, EDF stated its preference would be for PHMSA to adopt the API RPs but examine the non-mandatory provisions of the API RPs on a provision-by-provision basis to determine if any should be made mandatory, and adopt additional regulatory requirements to fill in potential gaps in the final rule.

TransCanada, which participated in the development of RP 1171, stated that the inclusion of both ''should'' and ''shall'' in the RPs reflected a deliberate, iterative, consensus-building effort that resulted in the selection of those specific words. TransCanada went on to say that it would not be prudent to make such recommendations mandatory because doing so could lead to a misplaced effort to document exceptions when operators should be focusing on the imperatives of IM and the development of effective procedures.

2. PHMSA's Response to Comments on Its Modification of the API RPs 1170 and 1171

After considering the petition for reconsideration and public comments, PHMSA is accepting the recommendation to adopt the RPs 1170 and 1171 as originally written by API, without modification. When drafting the IFR, PHMSA needed to provide an immediate and reasonable means by which it could begin regulating UNGSFs, while, at the same time, implementing sections 12 and 31 of the PIPES Act. As discussed earlier, section 12 of the PIPES Act required PHMSA to consider existing industry standards and recommendations from the Interagency Task Force (created by section 31) as the basis for its pending regulations. In its 2016 report, the Interagency Task Force recommended that PHMSA consider ''incorporating existing industry-recommended practices API RP 1170 and 1171 into the part 192 regulations, and they should be adopted in a manner that can be enforced.'' Historically, PHMSA has successfully incorporated by reference many industry standards, guidance, and recommended practices in lieu of developing its own regulations.

After additional review, PHMSA has determined that adopting the RPs as originally published by API would still provide significant benefits for safety, the environment, and public health but would be much easier for the regulated industry and the public to understand and for PHMSA to interpret and enforce. The non-mandatory provisions in the RP provide operators with guidance for optional considerations based on the features and characteristics of individual storage facilities. However, the RPs still require all operators to develop policies and procedures to ensure the functional integrity of UNGSFs and to inspect and verify the operational integrity of these facilities on a site-specific basis and will provide PHMSA with a stronger basis upon which to base enforcement than the IFR.

As the Associations pointed out in their petition for reconsideration, the existence of ''non-mandatory provisions in the RPs does not affect their overall enforceability.'' Throughout the RPs, there are many broad mandatory provisions that operators of UNGSFs must implement, using a range of options considered in accompanying non-mandatory provisions. The non-mandatory provisions provide operators with illustrations, examples, or choices of action for how to achieve compliance with the mandatory provisions. Because these non-mandatory provisions are

closely tied to the mandatory provisions that operators must meet, any non-mandatory provision remains enforceable to the extent that it is necessary, in the context of a particular operator or facility, to ensure compliance with a mandatory provision in the Recommended Practice.

Based on the petition for reconsideration, the post-IFR comments received, as well as its experience with the application and enforcement of similar consensus standards and recommended practices, PHMSA believes that adopting the RPs in their original published form, will accomplish the goal of the IFR, which was to improve safety. The means of achieving this goal was to establish, for the first time, minimum Federal safety standards that would require operators of all UNGSFs to meet certain basic, uniform, and risk-based policies and procedures as outlined in the RPs. In evaluating regulatory alternatives, PHMSA did consider adopting a portion of the ''should'' provisions to identify and address any potential gaps, but PHMSA ultimately decided not to because the Agency does not have sufficient information to identify whether there are ''should'' statements that are, on average, more or less practical and necessary at each site, and thus would be more or less likely to cause operators to seek deviations. In light of this factor and the comments received, PHMSA is convinced that treating the non-mandatory provision as written in the RPs is the better course of action because it adds clarity to the provisions which should help improve compliance while providing at least an equivalent level of safety as the IFR.

The IFR and this final rule are PHMSA's first effort to establish a national regulatory program for UNGSFs. This program includes features such as basic reporting requirements, Federal and State inspections, and a Federal-State partnership that will enable States to go beyond the RPs by adding additional or more stringent requirements. As the agency and the industry gain experience implementing this new regulatory program, they will learn what improvements need to be made. If experience shows that the RPs do not provide an adequate level of safety for certain activities or risks, PHMSA will consider the need to modify the regulations, as appropriate.

C. Compliance Timelines

The IFR required that UNGSFs constructed before July 18, 2017, meet all operations, maintenance, integrity demonstration and verification, monitoring, threat and hazard identification, assessment, remediation, site security, emergency response and preparedness, and recordkeeping provisions of the applicable RPs within one year from the effective date of the IFR, *i.e.,* January 18, 2018. Specifically, existing UNGSFs using a solution-mined salt cavern for storage were required to meet the requirements of RP 1170, sections 9, 10, and 11, and operators of existing UNGSFs using a depleted hydrocarbon reservoir or an aquifer reservoir for gas storage were required to meet the requirements of RP 1171, sections 8, 9, 10, and 11, by the same date.

Following the publication of the IFR on December 19, 2016, PHMSA published FAQ guidance (April 2017) to assist operators in applying the RPs. The FAQs included a suggested timeline for operators to complete the risk analysis and baseline assessments for the requirements in the IFR.

1. Comments on the Compliance Timelines

PHMSA gave operators one year from the effective date of the IFR to comply with the IFR. Commenters stated that the timeline for compliance provided in the IFR was unreasonable, and PHMSA's expectations for operators were unclear. Commenters requested that the final rule adopt phased-in compliance timelines, as PHMSA has done in previous rulemakings. Most commenters recommended that PHMSA follow the timelines published in its Underground Natural Gas Storage FAQs (April 2017).

Most industry commenters asked that PHMSA modify the compliance timelines to break it up into phases and extend the overall schedule, similar to what the FAQs outlined, which suggested that operators complete the baseline integrity assessments of each storage field within three to eight years. These commenters agreed that the FAQ's timelines for baseline integrity assessments were realistic and that any shorter timeframe was unrealistic and impracticable. They supported including clear, phased-in timelines in the final rule. Most said it would take longer than 12 months to implement all aspects of the RPs fully and that the PHMSA should extend the compliance deadline.

The Associations requested that the final rule incorporate the risk assessment and integrity-management timelines currently outlined in the FAQs.[22] The Associations doubted that PHMSA had intended to require operators to implement all actions under the applicable sections of the RPs within one year. In their comment, the Associations spoke of an operator that had recently implemented the RPs at its facility. The operator reported that it took over 18 months to gather the subject matter experts and complete the integrity plans and operating procedures. The Associations added that operators should expedite the implementation of preventive and mitigative measures for high-risk or imminent-risk facilities, as identified by their risk assessments.

Similarly, TransCanada stated that it was impractical to implement the IFR by January 18, 2018, and asked that PHMSA clarify in the final rule what the agency expected operators to have achieved by January 18, 2018, and beyond. TransCanada agreed, with certain reservations, that baseline risk assessments could begin within one to two years of the effective date of the final rule. They also agreed that three to eight years was enough time to complete risk assessments for all individual wells at UNGSFs.

2. Response to Comments on the Compliance Timelines

PHMSA is accepting the commenters' recommendations to reconsider the compliance timelines in the final rule. These timelines are similar to the ones published PHMSA's Underground Natural Gas Storage FAQs (April 2017). Below is a summary of the compliance timelines for implementing a UNGSF program.

Deadline for Written Procedures

Consistent with the IFR, operators must prepare and follow written procedures for the operations, maintenance, and emergency management and response activities outlined by the applicable RPs. However, this final rule removes the requirement in the IFR that these procedures be incorporated into an operator's existing procedural manuals required for gas pipelines under § 192.605. Instead, the final rule replaces this provision with a similar requirement that UNGSF operators develop written procedures for carrying out the final rule and maintain and update them in a similar fashion as required by § 192.605 for gas pipelines. In the final rule, the new requirement is in a new paragraph exclusive to UNGSFs under § 192.12.

Accordingly, operators must establish and follow written procedures for implementing their UNGSF programs. By January 18, 2018, all operators with

[22] ''Underground Natural Gas Storage FAQs,'' issued by PHMSA in April 2017.

facilities constructed on or before July 18, 2017, must have established and put into service procedures for operations, maintenance, and emergency preparedness. All other operators must have these procedures in place prior to commencing operations. Operators must also establish an interval for reviewing and updating these written procedure manuals, not exceeding 15 months, but at least once each calendar year.

Integrity Management Framework

By January 18, 2018, all operators with facilities constructed on or before July 18, 2017, must have established a framework for IM under the IFR. All other operators must have this framework in place prior to commencing operations. An initial framework means a written explanation of the mechanisms or procedures the operator will use to implement each program and API RP to ensure compliance with this final rule. These procedures, implementation framework, and schedules do not need to be fully fleshed out but must be sufficient for putting the program in place over the long term. PHMSA expects that each operator's implementation framework and schedules will evolve into a more detailed, comprehensive, and robust program as the operator's program matures. An operator must make continual improvements to the program.

The IM framework for a UNGSF must include:

- A plan for developing and implementing each program element;
- An outline of the procedures to be developed;
- The roles and responsibilities of UNGSF staff assigned to develop and implement the procedures;
- A plan for how staff will be trained in awareness and application of the procedures;
- Timelines for implementing each program element, including the risk analysis and baseline risk assessments; and
- A plan for how to incorporate information gained from experience into the IM program on a continuous basis.

Timelines for Conducting Risk Assessments

By four years after the effective date of this final rule, each operator must have completed baseline risk assessments for 40 percent of all its wellbores, wellheads, and associated components. Operators should generally prioritize assessments on higher-risk wells first, based on a matrix of identified threats, hazards, and the likelihood of their occurrence. Operators must complete baseline assessments of all reservoirs and caverns by the same date. By seven years after the effective date of this final rule, operators must have completed baseline risk assessments for all remaining wellbores, wellheads, and associated components. This implementation period is similar to the one published in PHMSA's Underground Natural Gas Storage FAQs (revised April 2017).[23]

D. Placement of Underground Storage Regulations in a New Part for Title 49 of the 49 CFR

The IFR added requirements in parts 191 and 192 for UNGSFs that cover reporting, recordkeeping, design, construction, and operation and maintenance procedures and practices. Before the IFR, there were no Federal regulations pertaining directly to UNGSFs. While part 192 already covered much of the surface piping at these facilities, up to the wing-valve assemblies on the wellhead at UNGSFs served by pipeline, PHMSA had not previously issued rules for the actual wellhead or ''downhole'' portion of these facilities.

1. Comments Requesting a New Part for Title 49 of the CFR

The IFR amended parts 191 and 192 to add underground natural gas storage regulations. For several reasons, commenters requested that PHMSA create a new ''part 19x'' in subchapter D of title 49 of the CFR that would contain regulations exclusively for underground storage. Generally, their interest was in differentiating the requirements for UNGSF from those requirements for other types of regulated gas facilities.

The Associations and some operators recommended that PHMSA remove the underground storage regulations from part 192 and place them in a new part under subchapter D in 49 CFR. They asserted that moving UNGSF regulation to a new part in the pipeline safety regulations would clarify the application of the regulations both now and in future rulemakings. The commenters stated that because the existing definitions of pipeline and pipeline facility in § 192.3 were so similar to the definition of underground natural gas storage facility (also in § 192.3) that it was unclear how to apply the regulations.

The Associations also expressed concern that because the IFR placed the underground storage regulations in part 192, operators might mistakenly apply the engineering regulations specific to other pipeline facilities to UNGSFs—or vice-versa. The RPs contain design, construction, and IM practices for UNGSFs that the Associations believed are considerably different from the practices for other pipeline facilities outlined throughout part 192. They provided examples of regulations that, if misapplied, might result in unsafe practices. The Associations asserted that PHMSA could avoid these potential conflicts by placing the UNGSF regulations in a new part under 49 CFR subchapter D, separate from part 192.

Several commenters, including Dow Chemical Company, claimed that adding underground storage regulations to part 192 would generate confusion. Specifically, commenters said that the IFR was unclear as to which sections of part 192 applied to UNGSFs and which ones to other gas pipeline facilities. The GPTC expressed the view that the definition of underground natural gas storage facilities in § 192.3 overlapped with the existing definitions of pipeline facilities and transmission pipelines and that it believed PHMSA intended to expand the regulatory scope of parts 191 and 192 to UNGSFs. However, GPTC implied that the overlap between the new definitions and the new regulations' placement in part 192 would create confusion as to the applicability of the RPs to pipeline facilities already regulated under other subparts of part 192.

Similarly, PG&E requested that the final rule revise the pipeline safety regulations to specify which parts of 49 CFR subchapter D applied to underground natural gas storage, instead of providing clarification through agency guidance materials (*e.g.,* FAQs). They stated that PHMSA historically had not incorporated FAQs addressing additional programs, such as ''Integrity Management,'' ''Drug and Alcohol Testing,'' and ''Gathering Lines,'' into regulatory language. PG&E stated that it believed this practice would leave operators at risk of being forced to comply with requirements that did not appear in regulatory language. Therefore, PG&E encouraged PHMSA to clarify § 192.12 by adding an exclusion for the subparts of part 192 that would not apply to underground natural gas storage. Other commenters shared this view and expressed concern that PHMSA would attempt to use FAQs or similar guidance documents instead of properly promulgated regulations.

2. Response to Commenters' Request for a New Part

Section 60101(a)(21) defines the term ''transporting gas'' as ''the gathering, transmission, or distribution of gas by

[23] *https://primis.phmsa.dot.gov/ung/faqs.htm.*

pipeline, or the storage of gas, in interstate or foreign commerce.'' The statute specifically lists the ''storage'' of natural gas as one component of ''transporting gas.'' Since all PHMSA's substantive regulations pertaining to the transportation of natural gas are in part 192, PHMSA believes the UNGSF regulations also belong in part 192.

Along with the public comments, PHMSA reviewed recommendations from the Interagency Task Force and a petition for rulemaking from INGAA. The Task Force recommended that PHMSA incorporate the RPs into part 192, with supplemental recordkeeping and reporting procedures as necessary. The IFR noted that INGAA had petitioned PHMSA on January 20, 2016—while the Aliso Canyon accident was still ongoing—to incorporate the RPs into part 192. Because UNGSFs are part of the broader natural gas transportation systems, part 192 is the most logical place for the new substantive regulations. Incorporating the requirements into parts 191 and 192 also subjects UNGSF operators to the requirements of part 190, for enforcement and regulatory procedures, and part 199, for drug and alcohol testing. Therefore, PHMSA had adopted these recommendations and by adding the UNGSF regulations in parts 191 and 192.

PHMSA agrees that the language in the IFR resulted in a certain level of ambiguity about the applicability of § 192.12 to other gas pipeline facilities and, vice versa, the applicability of other existing regulations to UNGSFs. PHMSA has addressed this issue by making two changes in this final rule. First, PHMSA is adding an introduction to § 192.12, which provides that the section contains minimum requirements for UNGSFs. This introduction means to clarify that § 192.12 only applies to UNGSFs and no other pipeline facilities. Second, the final rule also modifies the definition of a UNGSF to eliminate any potential overlap with other gas pipeline facilities covered elsewhere in part 192.

PHMSA also agrees with the commenters that the FAQs are guidance documents to help operators understand and implement rulemakings. FAQs are not the basis for PHMSA's enforcement of the rule. However, they can and should be used to clarify or explain PHMSA's interpretation of the scope and applicability of the regulation. For example, while not explicitly stated in the preamble or the amendatory language of the IFR, PHMSA explained through FAQs that operators of UNGSFs are subject to regulation under 49 CFR part 199, ''Drug and Alcohol Testing.'' Any operator of a ''pipeline facility'' that is subject to any subset of the part 192 regulations is required to test covered employees for the presence of prohibited drugs and alcohol. PHMSA also explained in the FAQs that operators of UNGSFs were not required to comply with the ''Qualification of Pipeline Personnel'' requirements contained in subpart N of 49 CFR part 192. The FAQs explained that operators must comply with the training requirements in API RP 1170 (section 9.7.5) or API RP 1171 (section 11.12), dependent upon the type of storage field. Both API RP sections describe general training parameters and specifically identify the need to train personnel for normal, abnormal, and emergency conditions. Additionally, this final rule makes it clear that UNGSFs are not subject to any requirements of part 192, aside from § 192.12.

E. Suitability of API RPs 1170 and 1171 as the Basis for Rulemaking

In the IFR, PHMSA incorporated by reference two industry Recommended Practices, API RPs 1170 and 1171, into 49 CFR part 192.

1. Comments Concerning the Suitability of the RPs for Rulemaking

PHMSA used RPs 1170 and 1171 as the foundation for the new minimum safety standards for UNGSFs. Commenters cited the forewords of both RPs, which state that the RPs were not intended to substitute for Federal or State regulations as the basis for objecting to their use as the basis for new regulatory requirements. Other commenters identified potential gaps in regulatory coverage in the RPs, such as risk management practices for solution-mined salt caverns. For these reasons, commenters stated that the RPs were not an adequate basis for regulation.

Some commenters were concerned with the suitability of the RPs as the basis for regulations. Texas RRC and EDF criticized PHMSA's approach to incorporating the RPs into the underground natural gas storage regulations. The Texas RRC stated that the RPs were neither drafted nor intended to operate with the force and effect of Federal regulations and, as such, should not be adopted as written. Similarly, EDF pointed to the scope section of RP 1170, which states that the document is ''intended to supplement, but not replace, applicable local, State, and Federal regulations.'' Both the Texas RRC and EDF said they understood the engineering merit behind the RP, but expressed a belief that the RPs were more suitable as guidance material for operators.

Most private citizens urged PHMSA to go beyond the safety provisions in the RPs. Notably, these commenters expressed concern over the lack of a specific ''risk management'' section in RP 1170 for solution-mined salt caverns. They asked that the final rule provide additional risk management practices for solution-mined salt caverns.

A few commenters were concerned that the provisions in the RPs were vague, ambiguous, and insufficient in detail. For instance, States First said that while the RPs contain substantial information and guidance for operators, ''it is [States First's] belief that [the RPs] require considerable wording revisions and additions to make them effective as regulations.'' Similarly, MDEQ stated that the IFR lacked clear timeframes and provided little regulatory oversight and approvals for certain actions taken. MDEQ expressed concern that in many instances, the IFR left it up to operators to determine the risks facing their facilities and the methods for addressing them. It went on to say that IFR created inconsistencies and uncertainties in providing the level of protection needed. These inconsistencies and uncertainties in the IFR, in turn, could make it difficult for State regulators to address safety issues for intrastate gas storage operations by implementing additional regulations beyond the IFR.

2. Response to Comments Concerning the Suitability of the RPs for Rulemaking

PHMSA disagrees with the commenters' broad assertion that the API Recommended Practices are an inadequate basis for regulations. PHMSA routinely participates in consensus-standards-setting organizations that address pipeline design, construction, maintenance, inspection, and repair. These standards represent the best practices of the industry and, therefore, should be considered in the development of potential regulation. Agency participation in the development of these voluntary consensus standards is vital to eliminate the necessity for development or maintenance of separate, government-unique standards.

Further, the PIPES Act specifically directs the Secretary to consider ''consensus standards for the operation, environmental protection, and integrity management of underground natural gas storage facilities'' and ''the recommendations of the Aliso Canyon natural gas leak task force established under section 31 of the PIPES Act of 2016'' (49 U.S.C. 60141(b)). As

discussed above, the Interagency Task Force issued a final report, titled ''Ensuring Safe and Reliable Underground Natural Gas Storage,'' making several recommendations. With respect to API RP 1170 and API RP 1171, the report recommended that ''[t]he incorporation of API RP 1170 and 1171 into the part 192 regulations will be an important step in improving the safety and reliability of underground gas storage facilities.'' [24] As a result, the report recommended that PHMSA consider incorporating the standards into part 192 in a manner that would make the standards enforceable.[25] After consideration of the RPs and the comments received concerning their incorporation, PHMSA concludes that the standards are sufficient to establish an initial, baseline level of regulation with the additions incorporated into this final rule. This initial regulatory framework will undoubtedly evolve and improve over time as PHMSA gains greater experience in this industry.

F. Integrity Management Practices

Integrity management is PHMSA's risk management program for identifying, assessing, and addressing potential threats that can have adverse consequences and a finite probability of occurring. The regulations in 49 CFR parts 192 (for gas pipelines) and 195 (for hazardous liquid pipelines) are a type of integrity management that PHMSA has applied to traditional pipeline systems. In place for over ten years, PHMSA's integrity management regulations had aided in the removal of thousands of defects from pipeline facilities before they failed and in the identification of preventive and mitigative measures to reduce the likelihood and consequences of failures potentially affecting high consequence areas. PHMSA expects that applying similar integrity and risk management practices to UNGSFs will have a similar effect on improving safety.

As discussed throughout this final rule, API RP 1170 and API RP 1171 outline the concepts of risk-based integrity management and provide instructions for the risk assessment and analysis process for UNGSFs. The IFR required operators of depleted hydrocarbon reservoirs and aquifer reservoirs to meet the risk-management requirements outlined in section 8 of RP 1171, which resembled PHMSA's existing IM program for gas and hazardous liquid pipelines. This section outlines the components of a process, including data collection, threat and hazard analysis, risk assessment methodology, preventative and mitigative measures, risk monitoring, and recordkeeping procedures.

The IFR did not contain a similar provision for operators of solution-mined salt cavern UNGSFs. The term ''Integrity Management'' is a systematic approach to analyzing and mitigating risk to promote the safe management and operations at a given facility. The IFR required operators of solution-mined salt caverns to meet the requirements of RP 1170, section 10, ''Cavern Integrity Monitoring,'' which directs operators to develop a holistic approach to maintaining well integrity but does not outline the components of an integrity-management process as explicitly as section 8 of RP 1171.

1. Comments Concerning Integrity Management Practices

As written, the risk-management practices in API RP 1170 (for solution-mined salt caverns) lack the specificity of the risk-management practices in section 8 of API RP 1171 (for depleted hydrocarbon reservoirs and aquifer reservoirs). Commenters identified the lack of robust risk management practices as a safety gap in the integrity program for solution-mined salt caverns and requested that the final rule supplement what is currently prescribed in API RP 1170.

Several commenters expressed concern that the RPs and, consequently, the IFR, lacked specific risk management criteria for solution-mined salt caverns. As Gas Free Seneca stated, RPs 1170 and 1171 mirror each other in every respect except for risk management. Gas Free Seneca, EDF, and some private citizens requested that the final rule add risk management standards for solution-mined salt caverns like the standards that exist for depleted hydrocarbon and aquifer reservoirs contained in section 8 of RP 1171.

EDF stated that the IFR called for depleted hydrocarbon and aquifer reservoir operators to develop risk management plans that address risks and provide plans to mitigate those risks. In its comments, EDF suggested that such a plan would be a good supplement to the regulations for solution-mined salt caverns. It stated that adding a risk management plan as a requirement in the final rule would be consistent with the natural gas storage rules being considered by California regulators following the incident at Aliso Canyon.

Gas Free Seneca, States First, EDF, and some private citizens requested that PHMSA mandate risk-acceptance criteria for underground natural gas storage facilities. Gas Free Seneca and private citizens asked that PHMSA set a measurable limit for risk and specify the types, frequency, and methods operators must use to collect and conduct risk analyses. States First asked that PHMSA set an acceptable level of risk so that operators would be required to meet an established standard, irrespective of their self-defined ''capabilities.'' EDF added that the final rule would benefit from the use of a risk-management ''heuristic'' such as ''ALARP,'' an acronym that stands for ''As Low as Reasonably Practicable.'' According to EDF, ALARP provides a process by which the regulated industry and the regulator can work together ''to systematically set appropriate levels of risk reduction.'' [26]

2. Response to Comments Concerning Integrity Management Practices

Based on the commenters' suggestions, and supported by an Interagency Task Force recommendation, PHMSA is making several enhancements to the integrity management provisions of the final rule. First, PHMSA is extending the risk management provisions of section 8, to salt-cavern UNGSFs, to the extent they apply to the physical characteristics and operations of solution-mined salt caverns, within one year of the effective date of the final rule. In other words, the final rule requires that UNGSFs using solution-mined salt caverns generally conform to the risk management practices that apply to UNGSFs using depleted hydrocarbon and aquifer reservoirs.

There are several reasons for this change. As discussed earlier, risk management is a standard concept in the oil and gas industry, although different programs may use slightly different terminology. Additionally, the Interagency Task Force recommended that PHMSA incorporate risk management practices into its regulations. During its initial site assessments, PHMSA observed that operators of solution-mined salt caverns were already in the process of conforming to risk management practices like those detailed in section 8. RP 1170 does address certain aspects of risk management practices but is less

[24] ''Ensuring Safe and Reliable Underground Natural Gas Storage,'' Final Report of the Interagency Task force on Natural Gas Storage Safety; October 2016. See pg. 63–64 of the final report at *https://www.energy.gov/downloads/report-ensuring-safe-and-reliable-underground-natural-gas-storage.*

[25] Ibid.

[26] ALARP is a principle more common in European law that sets an acceptable level of risk *as low as reasonably practicable.*

comprehensive than RP 1171. For instance, section 10.2 of RP 1170 requires operators to ''take a holistic and comprehensive approach to monitor cavern integrity,'' which would include the identification and assessment of risks. Section 10.2 of RP 1170 goes on to say there is no single best method to achieve thorough cavern-integrity monitoring, thus leaving it up to an operator to evaluate the risks of each specific facility.

While the scope of RP 1171 is specific to depleted-hydrocarbon and aquifer reservoirs, much of section 8 is general enough that operators can readily apply the practices across all types of UNGSFs. PHMSA believes requiring the risk-management practices outlined in section 8 to all UNGSFs is the most practical method of directing all operators to manage the risks of gas storage releases on a case-by-case, facility-specific basis. This approach gives operators the flexibility to determine what actions are appropriate.

Second, § 192.12(d) uses slightly different terminology than what was used in the IFR to describe the risk management provisions that operators must follow. Whereas subsection 8.1 is titled ''Risk Management for Gas Storage Operations,'' § 192.12(d) is titled ''Integrity management program.'' This change is intended to confirm that the risk management program under the final rule has been broadened beyond what is provided solely under the RPs and that it is a variation of the IM programs established under parts 192 and 195 for gas transmission pipelines, interstate liquid pipelines, and gas distribution systems. The industry generally uses the term IM to describe the risk-management provisions of section 8, so it should be less confusing and more consistent to use the term IM to refer to all four integrity-management programs applicable to PHMSA-regulated pipeline facilities,[27] even though the details of each program vary slightly.

Third, as noted in the FAQs, this initial IM framework for depleted hydrocarbon and depleted aquifer reservoir UNGSFs that were constructed prior to July 18, 2017, and were subject to section 8 under the IFR, had to be in place by January 18, 2018. These operators must now implement a full IM program that includes the new provisions in the final rule within one year from the final rule's effective date.

Fourth, this final rule requires a slightly different process for UNGSF operators to develop a robust IM program, depending upon whether the facility is a depleted hydrocarbon or a depleted aquifer reservoir or whether it is a solution-mined salt cavern. For the former, the first step is to put together an initial ''framework'' based on the provisions of section 8, including:

- A general discussion or definition of risk management;
- Data collection and integration;
- Threat and hazard identification and analysis;
- Risk assessment;
- Preventive and mitigative measures;
- Periodic review and reassessment; and
- Recordkeeping.

For existing solution-mined salt cavern UNGSFs, they must implement a full IM program within one year from the effective date of the final rule. For new facilities constructed after the effective date of the final rule, they must have a full IM program in place before they commence operations. In addition, the final rule allows solution-mined salt cavern UNGSFs greater flexibility in meeting the provisions of section 8 by requiring that they meet only those provisions of section 8 that are applicable to the physical characteristics and operations of a solution-mined salt cavern. The two timelines differ because operators of solution-mined salt cavern facilities did not receive notice of having to meet the IM provisions of section 8 ''that are applicable to the physical characteristics and operations of a solution-mined salt cavern UNGSF.'' PHMSA believes that such a limitation on the IM program for solution-mined salt caverns is reasonable and readily ascertainable by operators of such facilities.

Fifth, in addition to the general framework outlined in section 8, the final rule includes several specific IM requirements for all UNGSF operators. Each operator's plan must include the following:

- A plan for developing and implementing each program element to meet the requirements of the final rule;
- The roles and responsibilities of UNGSF staff tasked with developing and implementing the IM program;
- An outline of the IM procedures to be developed;
- A plan for how staff will be trained in awareness and application of the operator's IM program;
- Timelines for implementing each IM program element, including the risk analysis and baseline risk assessments; and
- A plan for how to incorporate information gained from experience into the IM program on a continuous basis.

Because these are new, more specific requirements than those contained in the IFR, operators of existing UNGSFs will have an additional year to comply.

Sixth, PHMSA establishes a schedule for conducting the initial or ''baseline'' assessments for each reservoir or cavern and all wells. PHMSA has based this schedule on commenters' recommendations to use a ''phase-in'' timeline, similar to the UNGSF FAQs published in April 2017. The final rule requires that operators complete all baseline assessments for reservoirs and salt caverns and 40 percent of the baseline assessments for individual wells within four years from the effective date of this final rule. Operators must start with the higher-risk wells, as identified through the operator's risk-analysis process. The remaining 60 percent must be completed within seven years from the effective date of this final rule.

Seventh, the final rule requires that operators conduct periodic reassessments under API RP 1171, subsection 8.7, on a risk-based schedule. This final rule establishes that reassessment intervals must be no more than seven years. PHMSA assumed that the stress conditions for the downhole piping used at the well site are similar to the stress conditions for buried pipe. Because of this, PHMSA chose a seven-year reassessment (maximum) interval to be consistent with other gas pipeline regulations. However, an operator could determine its reassessment interval should be less than seven years based on its risk-based assessments.

Seventh, the final rule makes clear that operators may use one or more risk assessments completed before the effective date of the rule to establish a baseline assessment, so long as they meet the requirements of section 8 of RP 1171, and continue to be relevant and valid for the current operating conditions and environment. These requirements are consistent with the FAQs published in April 2017.[28] This requirement is intended to prevent operators from reproducing assessments that already meet the requirements of this final rule. The criteria and timing for reassessments should be determined using results from baseline assessments and updated risk analyses in accordance with section 8. Operators may also conduct new or additional assessments to supplement prior assessments as

[27] The integrity management provisions for gas transmission pipelines are found at §§ 192.901 through 192.951, for gas distribution pipelines at §§ 192.1001 through 192.1015, for hazardous liquid pipelines at § 195.452, and for UNGSFs at § 192.12, as amended by this final rule.

[28] *https://www.phmsa.dot.gov/pipeline/underground-natural-gas-storage/ungs-frequently-asked-questions.*

necessary to establish a thorough understanding of a facility's risks.

Eighth, the final rule requires that operators maintain IM records in the same manner as pipeline operators are required to keep records under other IM provisions in parts 192 and 195. Maintaining IM records is critical if operators are to properly understand their systems, track and learn from experience, and to make continuous improvements. These records document how and why decisions are made to identify risks, set priorities among risks, conduct assessments, and identify and carry out preventive and mitigative measures. Further, operators must maintain IM records for the life of the UNGSF to demonstrate compliance with all the requirements under § 192.12(d). This level of documentation includes any calculation, amendment, modification, justification, deviation and determination made, and any action that is taken to implement and evaluate any element of an IM program. This level of documentation is the same standard found in § 192.947 for gas transmission systems and § 195.452(l) for hazardous liquid transmission systems.

Regarding the commenter's suggestion that PHMSA should apply a ''risk-tolerance'' model such as ALARP, PHMSA believes such a change is unnecessary. Integrity Management (IM) is one of many different varieties of risk management models used by different industries and organizations to handle safety risks to people and the environment. PHMSA's IM regulations require pipeline operators to identify the unique risks specific to their facilities comprehensively and to address those risks through a continuous program of gathering and analyzing data and learning from experience. PHMSA's approach places the onus on operators to identify, prioritize, and handle the risks posed by pipeline accidents. The IM requirements in this final rule are designed to be interpreted and applied essentially the same as the IM regulations currently applied to gas and hazardous liquid pipelines.

PHMSA believes that the integrity program outlined in § 192.12(d) and the RPs provides a flexible model that accounts for the diversity and variability of all UNGSFs, so long as the practices are risk-based and rigorously applied. To introduce a new model, such as ALARP, just for underground gas storage facilities and not other pipeline facilities, could be confusing for operators, PHMSA inspectors, and the public. Further, PHMSA is not aware of evidence that the ALARP model would provide an increase in safety.

G. Notification Criteria Under 49 CFR Part 191 for Changes at a Facility

The IFR added reporting requirements in 49 CFR part 191. PHMSA requires four types of reports from operators of UNGSFs: (1) Annual reports, (2) incident reports, (3) safety-related condition reports, and (4) National Registry information. PHMSA required this information because there was no that UNGSF operators follow the same provisions that gas pipeline operators must follow for providing PHMSA with notification of changes at their facilities.

Regarding the last type of report, PHMSA required National Registry information to identify the facility operator responsible for operators through an Operator Identification Number (OPID). The IFR required operators to notify PHMSA no later than 60 days before certain changes occur, including:

- Construction of a new UNGSF facility;
- Abandonment, drilling, or ''workover'' of an injection, withdrawal, monitoring or observation well. Concerning well workovers, the IFR stated that such work included the replacement of a wellhead, tubing or casing; and
- Changes in the entity (including company, municipality, etc.) that is responsible for an existing UNGSF and the acquisition or divestiture of an existing facility.

PHMSA clarified the IFR's notification requirements through April 2017 FAQs. For example, an operator should notify PHMSA of a ''replacement of a wellhead, tubing or casing.'' The FAQs said a ''replacement'' in this context meant the ''complete removal of the existing component and replacement with a new component (including replacement of wellhead, tubing, or casing).'' The FAQs further explained that there was no need for an operator to notify PHMSA of routine maintenance or repairs to existing components. The FAQs went on to say that operators should submit separate notifications for each storage field, but could bundle multiple activities within the same storage field in a single notification.

1. Comments on Notification Criteria Under 49 CFR Part 191 for Changes at a Facility

The IFR required UNGSF operators to notify PHMSA no later than 60 days before certain changes took place at their facilities took place, including changes in the operator of a facility and major new construction, as is currently required for other pipeline facilities. Operators found this reporting requirement excessive and recommended a monetary or activity threshold to reduce the volume of notifications. These commenters believed that the IFR's 60-day notification (reporting) requirement for new construction and construction-related activities was ambiguous and would result in excessive notifications. Some commenters expressed concern that the provision failed to exempt emergencies where advance reporting would be impractical.

LMOGA and TransCanada contended that PHMSA's notification requirement would duplicate their reporting burdens and cause delays because operators already had to notify states of construction activities and permitting. LMOGA expressed concern that a 60-day-notice to PHMSA for certain construction activities, such as well workovers, could shut down wells for an unnecessary amount of time. It stated that, currently, work permits for well workovers are issued by states in one to three days. TransCanada contended that PHMSA should remove the 60-day-notice requirement for new construction from the final rule altogether. It suggested that PHMSA could capture this same information through the annual report and safety-related condition reports instead of creating a separate notification requirement.

GPTC, PG&E, and others suggested other ways to streamline or reduce the notification burden involving new construction. For example, GPTC suggested that the final rule limit advance notifications to only those well workovers where a well was killed, a plug placed in the well for work, or a rig installed.

Another suggestion from PG&E was for PHMSA to adopt a monetary threshold for new-construction notifications, provide an exemption for emergency work, and define what activities would constitute a ''well workover.'' Regarding the monetary threshold, PG&E recommended that PHMSA only require operators to report well-workover and new-construction activities that cost more than $2 million. The company noted that PHMSA currently limits pipeline notifications [29] to those projects involving a certain minimum mileage or monetary threshold; it argued that applying similar thresholds for UNGSFs could reduce the reporting burden on operators.

[29] 49 CFR 191.22(c)(1)(i).

2. Response to Comments on Notification Criteria Under 49 CFR Part 191 for Changes at a Facility

The purpose of the 60-day notification requirement in the IFR is to alert PHMSA of upcoming critical well work that requires an operator to control well pressure. One example of such a well-control activity is well abandonment. If an operator incorrectly performs an abandonment, then brine fluid or natural gas may migrate through the wellbore and escape into drinking-water aquifers or to the surface. If notified in advance, PHMSA will have the opportunity to review the operator's pre-work plan and observe the in-progress work. Ultimately, this process is beneficial for the operator and public safety because it ensures a comprehensive assessment of the operators' methods. Such notifications could prevent an incident or more costly remediation work. PHMSA will have the opportunity to review an operator's records of the project but, because most of the work is underground, reviewing the work in real-time is ideal.

PHMSA agrees with the commenters that it should narrow the scope of the notifications for changes to a facility that would eliminate excessive reporting of minor or routine maintenance. Accordingly, this final rule limits required notifications to PHMSA to only those involving new construction and major maintenance work. Specifically, the final rule provides that operators must notify PHMSA of (1) any new facility construction; (2) maintenance work that requires a workover rig and costs $200,000 or more for labor, materials, and services; and (3) any plugging or abandonment activities, regardless of cost.

The scope of this modified notification requirement is limited to only those types of activities that require adherence to specific methods and techniques to prevent damage to the formations and to safely control pressure in the well. Bringing in a workover rig marks a step-change in the degree of complexity and scope of work. The presence of a workover rig means the operator is opening the well, rather than just doing some wing valve work at the surface. Opening a well (requiring a workover rig) usually infers serious maintenance or repair work, performing extensive logging and integrity evaluations, or replacement of downhole components.

Concerning the $200,000 maintenance-work threshold, PHMSA has not indexed this exact dollar amount across all states and activity types. During preliminary inspections, PHMSA observed what high-risk activities were occurring in the field and generally how much it costs operators to complete those maintenance activities. PHMSA is aware that the costs of pressure-control and remediation activities vary considerably, depending upon the depth of the well, pressure, casing type and size, and other factors. However, PHMSA believes this is an appropriate threshold level that captures the higher-risk activities and still reduces the volume and burden of notifications. There is the possibility that a workover rig is needed for some minor issues, where the cost falls below the 200k threshold. Again, most major activities with a workover rig will cost more than $200,000, thus triggering this type of notification. Note that PHMSA also allows operators to report multiple well activities within the same storage field in a single notification.

PHMSA also recognizes that the IFR inadvertently omitted an exception for emergency maintenance or repairs. If an operator reasonably determines that it needs to do work immediately, for safety reasons, then it should not delay the work because of the 60-day notification requirement. Accordingly, the final rule adds a provision that allows operators to notify PHMSA as soon as practicable in instances where 60-day notice is not feasible due to an emergency. In such cases, an operator must promptly respond to the emergency, notify PHMSA as soon as practicable, and document the emergency and the reason for any delay in notification.

H. The States' Role in Regulating UNGSFs

There are approximately 403 active underground natural gas storage facilities (UNGSFs) in the United States, with about a 60/40 split between interstate and intrastate facilities. Interstate UNGSFs serve interstate facilities, and PHMSA has exclusive pipeline safety jurisdiction over the design, construction, operation, and maintenance of these facilities. Intrastate UNGSFs, on the other hand, are facilities that provide gas storage for intrastate pipelines, most notably local gas distribution companies (LDCs). Generally, these intrastate gas pipeline facilities have been subject to State regulation by its public utility commission or oil and gas commission. Intrastate UNGSFs continue to be subject to State regulation, but only if the applicable State authority has filed a certification with PHMSA to participate as a full State partner under the new Federal program and receive Federal funding through PHMSA.

The Federal regulatory program for UNGSFs has been set up to mirror the existing Federal-State pipeline regulatory partnership for gas and hazardous liquid pipelines as established by the Natural Gas Pipeline Safety Act in 1968 and the Hazardous Liquid Pipeline Safety Act of 1979, respectively. Under this system, Congress has conferred on the Department primary jurisdiction over all natural gas and hazardous liquid (primarily oil) pipelines in or affecting interstate commerce but has preserved the states' role in regulating intrastate pipelines, as long as the State that chooses to submit an annual certification to PHMSA and agrees to enforce the minimum Federal standards in addition to any State regulations compatible with the Federal standards.

The PIPES Act directed PHMSA to expand its pipeline-safety regulatory program to include the storage of natural gas incidental to transportation, using this same Federal-State model. Just as various states had previously regulated intrastate natural gas pipelines before the passage of the Natural Gas Pipeline Safety Act of 1968, so too have many states regulated UNGSFs prior to the passage of the PIPES Act and issuance of the IFR. These states will be able to continue this important safety role as partners with PHMSA.

Under the IFR and this final rule, intrastate UNGSF facilities will be regulated in one of two ways. Depending upon State law, they will be regulated either by a certified State entity (*e.g.,* public utility commission or oil and gas commission), or, in the absence of a certified State partner, by PHMSA. Notably, section 12 of the PIPES Act expressly allows a State authority to adopt additional or more stringent safety standards for intrastate UNGSFs, provided such standards are compatible with the minimum Federal requirements. PHMSA interprets this to mean that any State authority that has filed an annual State certification with PHMSA under 49 U.S.C. 60105 to regulate UNGSFs may regulate and enforce its own additional or more stringent regulations against intrastate UNGSFs that fall under that authority's State jurisdiction, to the extent that the additional State standards are compatible with the Federal safety regulations. This arrangement is the same as the States' authority to regulate all other intrastate pipeline facilities under parts 192 and 195.

Accordingly, States that had UNGSF regulations before the adoption of the IFR may continue to implement any

additional or more stringent regulations that they currently enforce with respect to intrastate facilities, to the extent that such regulations are compatible with the minimum standards set by this final rule. For a State wanting to expand its authority to inspect interstate facilities under the final rule, it will be able to apply to PHMSA for discretionary interstate agent status under 49 U.S.C. 60106(b), just as a State authority today, may carry out such a role for other oil and gas pipeline facilities.

It is worth noting that neither the PIPES Act nor this final rule alters the existing role of the States in the siting or permitting of UNGSFs or their regulation of natural gas production. PHMSA has never exercised regulatory control over these issues for pipeline and will not be doing so under the final rule. Instead, the PIPES Act provides that all UNGSFs incidental to gas ''transportation'' are now subject to Federal minimum safety standards promulgated by PHMSA. Section 12 of the PIPES Act directs PHMSA to exercise this authority in conjunction with its State partners in the same manner as other pipeline facilities are regulated.

This means FERC and the States will continue to exercise their respective authorities over the permitting of UNGSFs. FERC reviews applications for the construction and operation of UNGSFs owned by interstate gas pipeline operators and that are integrated into their pipeline systems. In its application review, FERC requires an applicant to certify that it will comply with DOT safety standards. While FERC has no jurisdiction over pipeline safety, PHMSA and FERC actively collaborate to exercise their respective responsibilities.[30]

PHMSA received several comments regarding the effect of the IFR on the role of the states in UNGSF regulation. These comments dealt primarily with concerns expressed by State regulators and gas-storage operators over PHMSA's role and the nature of the Federal-State partnership under this new regulatory scheme. These commenters also asked PHMSA to explain the roles of the various parties in permitting UNGSFs, to discuss the potential conflicts that may arise between existing State regulations affecting underground storage and the new Federal minimum safety standards and the degree to which certain existing State regulations will continue to apply to interstate UNGSFs. Of particular concern was whether the IFR could serve to undermine or reduce the existing level of safety and environmental protection that several States have been applying to interstate UNGSFs, especially where certain State standards could arguably be viewed as broader or more stringent than the RPs being adopted in the final rule. These comments are discussed below in more detail.

1. Comments on State Permitting of UNGSFs

In its comments, the Texas RRC asked PHMSA to clarify the States' role in permitting UNGSFs and commented that the IFR provided no specific details regarding permitting areas that fall to the states.[31] The commission noted that while the IFR accurately stated that permitting of gas wells is not a PHMSA function, PHMSA had incorrectly concluded: ''that the traditional role of permitting intrastate facilities falls to the states and the permitting of interstate facilities falls to the Federal Energy Regulatory Commission (FERC).'' According to the Texas RRC, ''FERC is not set up to conduct permitting of individual wells, ensuring proper notification is provided to all entitled parties, reviewing and adequately protecting groundwater, and protecting correlative rights.'' Conversely, the Texas RRC explained that under Texas law, the Texas RRC is directed to regulate the downhole portion of UNGSFs to fulfill its mandate to conserve State natural resources and to protect the environment. Therefore, it argued, ''all of these functions must fall to the State regardless of whether a well is part of an intrastate or interstate facility.'' Finally, the Texas RRC argued that the failure of PHMSA to properly address these scenarios ''indicates a lack of a clear understanding of underground natural gas storage and the historical role many states have had in its successful regulation of underground hydrocarbon storage.''

Similarly, Dow Chemical asserted that many states had established successful regulations and standards for permitting, operations, maintenance, monitoring, and other issues related to UNGSFs. The company pointed out that states with underground-storage safety regulations typically regulate both intrastate and interstate facilities. Along with Dow Chemical, LMOGA, MDEQ, and the Texas RRC recommended that PHMSA consult with State regulatory agencies to avoid unnecessary reporting and compliance programs and to learn from the states' experience in regulating UNGSFs as it continues to develop Federal regulations.

2. Response to Comments on the State Permitting of UNGSFs

As for the comments seeking greater clarity on how the IFR affects State permitting of UNGSFs, PHMSA has not made any changes to the regulatory text because PHMSA does not have the authority to prescribe the location or siting of UNGSFs. This final rule also does not deal with permitting, directly. Section 12 of the PIPES Act expressly states that the Act shall not be construed to authorize PHMSA ''to prescribe the location of an underground natural gas storage facility'' or ''to require the Secretary's permission to construct'' a UNGSF.

3. Comments on State Regulation of UNGSFs Associated With Gas Production

IPAA, EDF, and Hilcorp requested that PHMSA clarify how the IFR applied to UNGSFs associated with gas-production facilities. IPAA stated that the Pipeline Safety Laws do not provide PHMSA with authority to regulate gas-production facilities, citing 49 U.S.C. 60101(a)(21)(A) and 60101(a)(22)(B). IPAA, EDF, and Hilcorp requested that PHMSA add an exception to part 192, specifically excluding UNGSFs that are ''in direct support of'' (Hilcorp) or that are ''co-located with and used to support of'' (IPAA) production operations.

IPAA gave two examples of the types of production-related UNGSFs located in active production fields that are used to manage production operations, rather than providing ''commercial storage services.'' The first type was facilities that store gas from a production field but has not yet entered a PHMSA-regulated pipeline. The second type was UNGSFs that are used for gas production purposes ''after being delivered to the production field in a PHMSA-regulated pipeline.'' In other words, they store gas that has either not yet entered transportation or that has ended transportation. Under both scenarios, IPAA contended, the stored gas at these facilities is not incidental to transportation but is used to support gas production. According to these industry commenters, such UNGSFs are used in the process of extracting natural gas from the ground and should not be treated as providing storage incidental to transportation under the Pipeline Safety Laws.

[30] Page 28. *https://www.ferc.gov/market-oversight/guide/energy-primer.pdf.*

[31] *See State of Texas* v. *PHMSA,* No. 17–60189 (5th Cir. Mar. 17, 2017).

4. Response to Comments on UNGSFs Associated With Gas Production

The PIPES Act directed PHMSA to establish minimum Federal standards for all UNGSFs that store natural gas incidental to transportation. Again, the PIPES Act does not alter or expand PHMSA's jurisdiction as it has traditionally been applied to natural gas production or hazardous liquid production facilities. While PHMSA has never exerted jurisdiction over gas pipeline facilities that are engaged exclusively in production and has long recognized the authority of states to regulate the permitting and siting of pipelines and to protect groundwater and other State natural resources. Only after transportation has begun and before delivery to an end-user is there any issue of PHMSA jurisdiction, which is limited to the transportation of gas and hazardous liquids.

This is analogous to PHMSA's regulation of other types of temporary storage of hazardous liquid in transit. For example, petroleum being transported by pipeline is often stored temporarily along the line in one or more breakout tanks. These tanks are used to relieve surges or receive and store hazardous liquid transported by pipeline for eventual re-injection and continued transportation by pipeline (49 CFR 195.2). Similarly, under this final rule, a UNGSF is defined as a gas pipeline facility ''that stores natural gas underground and incidental to the transportation of natural gas'' in interstate or foreign commerce.

PHMSA interprets this to mean that if a UNGSF is used in any way to store gas that is received from a PHMSA-regulated pipeline and returns any of that stored gas to transportation by pipeline, then such a facility is incidental to transportation and therefore covered by this final rule. Even if some of that gas is used to support production operations or is mingled with produced gas that has not yet entered transportation, the storage facility itself will be treated as a UNGSF under the final rule and will be subject to PHMSA's full jurisdiction.

5. Comments on States' Regulation of Intrastate UNGSFs

Several commenters expressed concern that the IFR potentially conflicted with existing State regulation of intrastate UNGSFs and that the IFR lacked clarity on how such conflicts could be avoided or minimized. MDEQ, for instance, commented that its Oil, Gas and Minerals Division ran a regulatory program affecting many safety and environmental issues covered by the RPs and that ''Michigan's existing regulations are needed to fill gaps in the IFR particularly in the areas of permitting, liquid waste handling and disposal; and environmental protection from liquid hydrocarbons, brines, and other liquid contaminants.'' The agency further commented that the IFR ''makes no mention of pollution prevention, nor does it set standards for remediation of spills.'' It noted that many UNGSFs are located in oil reservoirs that still produce liquid hydrocarbons and brine, and that the State of Michigan has comprehensive regulations covering pollution prevention, groundwater monitoring, remediation, and clean-up activities. In short, the State urged PHMSA to ''recognize the states' role in these areas.''

6. Response to Comments on the States' Regulation of Intrastate UNGSFs

First, PHMSA recognizes and supports the role that many states have played for many years in the field of underground gas storage. Nothing in the IFR or this final rule is intended to minimize or diminish the states' role in ensuring the safety of UNGSFs, protecting the environment, or safeguarding critical State resources. Section 12 of the PIPES Act, however, mandates that PHMSA regulate all UNGSFs that storing natural gas incidental to transportation. Under 49 U.S.C. 60104(c) and the recently-enacted 49 U.S.C. 60141(e), states with existing regulations may continue to regulate intrastate gas storage facilities to the extent that the proper State authority becomes certified by PHMSA and the State regulations are compatible with the new Federal minimum safety standards.

Second, the PIPES Act and this final rule do not modify or undermine established principles of Federal preemption law as applied to pipeline safety. Any State regulation affecting PHMSA's exclusive jurisdiction over the safety of interstate pipeline transportation facilities is, and always has been, preempted by the Pipeline Safety Laws.[32] The enforceability of existing or new State regulations affecting gas production, storage, plugging, or other areas such as mineral rights, depends on whether the State regulations are based on an independent basis under State law and cannot be considered safety regulations preempted by the PIPES Act, which is necessarily a case-by-case determination.

Third, the PIPES Act and this rule represent a major step forward in extending minimum Federal safety standards to all interstate gas storage facilities, regardless of whether individual states have already adopted regulations governing storage facilities or whether individual interstate operators have voluntarily complied with existing State regulations. As PHMSA discussed in the IFR, interstate UNGSF facilities would not be subject to any regulatory safety requirements in the absence of this Federal action.

Fourth, PHMSA fully recognizes that states with UNGSFs typically have various regulations in place governing the construction, remediation, and plugging of gas wells. Before the IFR went into effect, many interstate UNGSF operators relied on these State regulations to help develop best practices. State safety jurisdiction, however, extends only to intrastate UNGSFs. Regulations differ from State to State, making it difficult for operators to maintain consistent performance across all their interstate facilities. Finally, PHMSA will incorporate lessons learned from operators and states implementing this final rule in the form of guidance and additional rulemakings. PHMSA understands that seeking input from states is a vital component in developing an effective underground natural gas storage program at the Federal level.

As for the comments regarding potential conflicts between existing State regulation of intrastate UNGSFs, three points should be made. First, many State agencies enjoy independent authority under their own particular State's laws to regulate UNGSF involving public health, protection of groundwater, allocation of mineral rights, and similar areas not involving safety. Under established Federal preemption law, States may regulate in such areas that are not preempted expressly by Federal law or regulation.

In the field of underground natural gas storage, Congress, through the PIPES Act, has conferred authority on the Secretary (and delegated to PHMSA) to provide for the safety of natural gas storage facilities incidental to transportation, just as it has for other oil and gas pipeline facilities. This authority covers the design, construction, operation, and maintenance of UNGSF facilities. States are precluded from regulating the safety of UNGSFs to the extent that such State regulations conflict with PHMSA's safety-related regulations. To determine whether specific State regulations are preempted by the PIPES Act and this final rule may require a fact-specific analysis of whether a particular State regulation has been preempted, an

[32] *See, e.g., Colorado Interstate Gas Company* v. *Wright,* 707 F. Supp. 2d 1169 (D. Kan. 2010).

analysis that falls within the purview of State and Federal courts. Such preemption determinations have routinely been made by the courts to resolve challenges to State and local governments' authority to regulate gas and hazardous liquid pipelines.

Second, any potential conflict between existing State regulations governing intrastate UNGSFs and Federal safety regulations disappears, in most cases, in those states that have submitted annual certifications to PHMSA and become UNGSF State partners. All State partners in this program will have the authority to adopt and enforce additional or more stringent safety regulations than the minimum Federal standards set forth in the IFR. PHMSA anticipates and hopes that many states, such as Texas, Michigan, and other commenters that already have existing regulations affecting intrastate UNGSF safety, will decide to partner with PHMSA and enjoy the enhanced authority, Federal funding, and other benefits that accompany State certification.

Third, PHMSA encourages and supports State regulatory programs that help ensure all UNGSFs, both intrastate and interstate, address resource conservation, environmental protection, land use, emergency response, and other important issues affecting gas wells and storage outside the realm of safety.

PHMSA agrees with MDEQ's comments and encourages MDEQ to examine its existing State UNGSF regulations to determine whether any of them are safety-related standards that could be preempted by this final rule in the event Michigan decides that it does not wish to become a certified State partner for intrastate UNGSFs. If Michigan does become a State partner for UNGSFs, then MDEQ (or other State authority in Michigan) will be able to apply additional or more stringent safety standards, provided they are ''compatible'' with the minimum Federal standards prescribed under the Pipeline Safety Laws and this final rule. If it chooses not to become a State partner for UNGSFs, then the Federal minimum safety standards will apply to all intrastate UNGSFs in Michigan, and PHMSA will inspect such facilities and enforce the Federal minimum standards against all intrastate UNGSFs in the State.

7. Comments on States' Regulation of Interstate UNGSFs

Some commenters, including EDF and the Interstate Oil and Gas Compact Commission, expressed concern that the IFR did not go far enough in exercising jurisdiction over UNGSFs in a manner that optimized existing State regulations. EDF commented that the new Federal regulations would create a ''ceiling'' on State regulations for the permitting, drilling, completion, and operation of underground storage wells that have also been applied to interstate facilities. EDF acknowledged that while interstate facilities are under the exclusive safety jurisdiction of PHMSA, intrastate UNGSFs are frequently subject to both safety regulations promulgated by PHMSA and to other gas-storage rules promulgated by State regulators that generally apply to all gas wells in their particular states. EDF expressed the fear that interstate UNGSF operators who had been ''voluntarily obeying State rules responding to the State's unique geology, level of subsurface activity, competing surface activities and general appetite for risk may, with the cover of PHMSA's IFR, decline to continue following those rules, possibly to the detriment of safety and the environment.''

To address this concern, EDF asked PHMSA to include two specific provisions in the final rule. First, it asked PHMSA to distinguish between those State regulations of general applicability to all oil and gas wells (*i.e.,* those falling within the jurisdiction ceded to states under the Natural Gas Act of 1938) and those addressing the special risks intrinsic to gas storage wells. EDF requested that PHMSA direct interstate operators to adhere to State regulations for permitting, drilling, completion and operation of storage wells, but ''only to the extent the regulations address risks of general applicability to all oil and gas wells and where it is not impossible to comply with both the State regulations and PHMSA requirements.''

Second, EDF asked PHMSA to require interstate operators in states having adopted ''storage'' regulations to identify all State rules that an operator believes are ''storage'' rules and address those rules in their risk management plans as part of the operators' preventive and mitigative measures to address ''special risks intrinsic to gas storage.'' According to EDF, this would serve to preserve the efforts made by some states to ensure safety and environmental protections imposed in the face of no minimum Federal standards.

8. Response to Comments on the States' Regulation of Interstate UNGSFs

As noted earlier, EDF and other commenters have pointed out that a number of interstate UNGSF operators in states with mature regulatory programs in place have been ''voluntarily'' obeying State rules. PHMSA acknowledges EDF's concern that some interstate operators may choose to no longer voluntarily comply with State UNGSF regulations that go beyond the new minimum Federal standards embodied in the final rule. However, the Federal standards do not disincentivize the voluntary compliance that was previously occurring before the IFR went into effect, provided that the voluntary compliance is compatible with the Federal standards. Therefore, it seems unlikely that an interstate operator who is already voluntarily complying with existing State safety-related standards would stop doing so because of this final rule unless voluntary compliance were to result in non-compliance with the Federal standard. Further, this is the same situation that exists with other State regulations that may affect gas and hazardous liquid pipelines and with which interstate operators may or may not choose to comply. For these reasons, PHMSA declines to modify the final rule to require interstate operators to take such State regulations into account in their IM plans or other procedures. The agency believes it would be inconsistent and impracticable to require operators to evaluate and include in their plans and procedures certain provisions of State regulations for UNGSFs but not for other pipeline facilities. This would put PHMSA in the untenable position of elevating certain State regulations for all interstate UNGSF operators but not for other State pipeline regulations. If PHMSA learns of State regulations that should be applied more broadly for all interstate UNGSF operators, it may consider amending its regulations through notice-and-comment rulemaking to make them applicable uniformly among all interstate operators.

I. Definitions and Terminology

The IFR added a definition for ''underground natural gas storage facility'' at 49 CFR 191.3 based on the definition provided in section 12 of the PIPES Act. The IFR's definition included the wellhead, downhole components, and associated onsite structures that lay within the scope of PHMSA's regulatory authority. The IFR provided no additional definitions.

1. Comments Regarding Definitions and Terminology

Several commenters asked that PHMSA modify the definition of ''underground natural gas storage facility'' in the final rule and to clarify or define other terms not defined in the IFR. Two commenters requested that

PHMSA create separate definitions for interstate and intrastate facilities. They said that clarification in the final rule would prevent jurisdictional confusion at the State level and enable their organizations to apply the rules more predictably.

Operators recommended a revised definition of ''underground natural gas storage facility,'' while others asked that PHMSA clarify the terms ''workover'' and ''modified well.''

The Associations recommended that PHMSA revise the definition of ''underground natural gas storage facility'' to avoid confusion with other subparts of 49 CFR part 192. They were concerned that the definition in the IFR included ''piping, rights-of-way, property, buildings, compressor units, separators, metering equipment, and regulator equipment,'' terminology that could imply components of a UNGSF were covered by both the underground natural gas storage regulations at § 192.12 and other provisions in part 192. They recommended that the definition of ''underground natural gas storage facility'' be amended to exclude ''facilities covered by part 192 of this chapter.''

The Associations further noted that the definition of a UNGSF included the term ''solution-mined salt cavern reservoir.'' They stated that the term ''reservoir'' is inaccurate in reference to salt caverns and recommended that PHMSA use the term ''a solution-mined salt cavern'' for technical accuracy. Similarly, the GPTC recommended that the final rule revise the definition of UNGSF to align with the scope of the RPs 1170 and 1171.

Similarly, PG&E recommended that PHMSA replace the definition of ''underground natural gas storage facility'' at § 192.3 with the following:

> ''Underground gas storage facility means a facility that stores natural gas in an underground facility incidental to natural gas transportation, which is constructed from a depleted hydrocarbon reservoir, an aquifer reservoir, or a solution-mined salt cavern. In addition to the reservoir, this also includes the injection, withdrawal, monitoring, observation wells, and associated wellhead equipment within the facility.''

PG&E also recommended that PHSMA remove the phrase ''including injection, withdrawal, monitoring, or observation well for an underground natural gas storage facility'' from the criteria for submitting a safety-related condition report under § 191.23. The company stated that because such equipment was already included in the definition of ''underground natural storage facility,'' operators might incorrectly conclude that two reports were required since the equipment was already covered under other provisions of part 191.

Northern Natural Gas, stated that the definition of a ''modified well'' was not clear and could be interpreted to include some minor or routine operations, such as the replacement of downhole equipment, casing repairs, or tubing changes.

2. PHMSA's Response to Comments Regarding Definitions and Terminology

PHMSA agrees with the commenters' suggestion to revise the definition of ''underground natural gas storage facility,'' and, therefore, is amending it in this final rule. The revised definition will better articulate the point of demarcation between facilities that constitute the UNGSFs and those that are part of other gas pipeline facilities. Traditionally, compressor units, buildings, and separators have been considered part of the ''topside'' pipe domain and are already regulated by other sections of part 192. These components can be connected to or from UNGSFs. PHMSA considers a UNGSF to include all components up to the valve assembly (and their flanges) that route gas at the wellhead to or from the connected pipeline(s). The valve assembly may be a single manual or automated valve or a combination of valves (*e.g.,* manual and emergency shutdown) and will be located near the wellhead.

With respect to the need for separate definitions for intrastate and interstate UNGSFs, PHMSA sees no need for such definitions. The use of the phrase ''incidental to natural gas transportation'' in 49 CFR 192.3 makes clear that the scope of PHMSA's jurisdiction over UNGSFs does not depend upon whether a facility is ''interstate'' or ''intrastate'' but whether it is tied to ''transporting gas,'' as that term is defined under 49 U.S.C. 60101(a)(21). This means that UNGSFs may include gas storage facilities that can be used occasionally or partially for production operations, such as enhanced recovery, gas lift, and for production equipment such as power generation and powering compressors and pumps.

Other commenters requested that PHMSA clarify common terms used throughout RPs 1170 and 1171, such as ''wellhead,'' ''workover,'' or ''modified well.'' For similar reasons, the final rule does not provide definitions for technical terms generally known to industry, such as ''wellhead,'' ''modified well,'' and ''workover.'' PHMSA will work with operators on a case-by-case basis should the need arise to determine the appropriate application of such terminology under the modified regulatory text in the final rule.

J. Requests for Additional or More Stringent Requirements

PHMSA received several comments from private citizens related to additional or more stringent requirements for UNGSFs that do not fit into the other categories already discussed. Gas Free Seneca, EDF, and several private citizens asked PHMSA to require the widespread use of subsurface safety valves. Some called for a plan to decommission UNGSFs. Others called for a moratorium on new facilities.

The widespread use of subsurface safety valves may have value but would require further study and research as to their effective use at each type of UNGSF over other safety enhancements or alternatives. In PHMSA's ongoing discussions with operators, the failure rates of subsurface safety valves during testing are variable. Additionally, once installed, an operator would have to re-open the well to make any repairs to the subsurface safety valve, requiring a workover rig to retrieve the valve. Given these factors, PHMSA would require additional certainty and a strong safety case before promulgating a Federal requirement for the widespread use of subsurface safety valves.

As for a moratorium, PHMSA does not have the authority to site UNGSF facilities (and, by extension, to ban new facilities) or to abrogate the power of states to issue permits. Therefore, a moratorium would be outside the scope of PHMSA's authority and contrary to the PIPES Act.

PHMSA recognizes that there are inherent risks to operating a UNGSF; however, Federal and State regulations minimize these risks by requiring operators to adhere to clear performance standards designed to maintain the integrity of the wellhead and reservoir or cavern. Furthermore, the addition of requirements in this final rule related to IM and recordkeeping will add greater rigor to the risk-management practices than in the IFR. In summary, the IFR and this final rule constitute the first large-scale application of PHMSA's regulation jurisdiction to UNGSFs. As operators begin applying the RPs and assessing the integrity of their facilities and as PHMSA gains experience in regulating UNGSFs, the need for any additional prescriptive measures will become apparent.

IV. Rulemaking Analyses and Notices

A. Statutory/Legal Authority for This Rulemaking

This final rule is published under the authority of the Federal Pipeline Safety Law (49 U.S.C. 60101 *et seq.*), as amended by the PIPES Act (Pub. L. 114–183, June 22, 2016). Section 60102 authorizes the Secretary of Transportation to issue regulations governing the design, installation, inspection, emergency plans and procedures, testing, construction, extension, operation, replacement, and maintenance of pipeline facilities. The Secretary has delegated her authority in this area to the Administrator of PHMSA (49 CFR 1.97). PHMSA is issuing the amendments to the requirements for UNGSF involved in pipeline transportation under this authority.

B. Executive Order 12866 and DOT Regulatory Policies and Procedures

This final rule is a significant action under section 3(f) of E.O. 12866. Therefore, the Office of Management and Budget (OMB) has reviewed it.

PHMSA prepared a regulatory impact analysis (RIA) for the final rule, which details the potential for incremental benefits and costs. The RIA, which is available in the docket for this final rule, Docket No. PHMSA–2016–0016, provides an estimate of the annualized cost savings of the final rule and the other alternatives considered relative to the baseline. Given the final rule does not impose any costs relative to the baseline (IFR), PHMSA determined that the final rule is not economically significant under Executive Order 12866 because the estimated annual impact is less than $100 million.

Under the final rule, PHMSA expects operators to continue performing the same preventative safety measures that they are performing under the IFR. Because PHMSA does not expect the final rule to change operator safety-related actions, PHMSA does not expect changes to the benefits relative to the IFR. Implementation of the IFR already achieved benefits that will remain in place, including the potential prevention of catastrophic natural gas releases due to the failure of storage wells and the associated impacts on human health, property, and the environment, including climate change.

PHMSA does anticipate cost savings once the final rule becomes effective. Using the IFR as a baseline, the final rule will reduce recordkeeping and reporting burdens, and burdens associated with technical evaluations of non-mandatory RPs. The estimated annualized cost savings as a result of these changes is $8,452,365 to $12,810,620 when discounted to present value at 7 percent.

C. Executive Order 13771

This final rule is considered an E.O. 13771 deregulatory action. Details on the estimated cost savings of this proposed rule can be found in the rule's economic analysis.

D. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) of 1980, as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA) of 1996, requires Federal agencies to consider the impact of their rules on small entities, analyze alternatives that minimize those impacts, and make their analyses available for public comments. The Act is concerned with three types of small entities: Small businesses, small nonprofits, and small government jurisdictions.

The RFA describes the regulatory flexibility analyses and procedures that Federal agencies must complete unless they certify that the rule, if promulgated, would not have a significant economic impact on a substantial number of small entities. A statement of factual basis must support this certification, *e.g.,* by addressing the number of small entities affected by the proposed action, calculating expected cost impacts on these entities, and evaluating economic impacts.

PHMSA estimated that this final rule would affect 130 operators. Of these 130 operators, there are 14 small entities. However, this final rule is a deregulatory action that will reduce the burden of information collections. Therefore, PHMSA has determined that this final rule will not have a significant economic impact on any small entities.

E. Unfunded Mandates Reform Act of 1995

Title II of the Unfunded Mandates Reform Act (UMRA) of 1995, Public Law 104–4, requires that Federal agencies assess the effects of their regulatory actions on State, local, and Tribal governments and the private sector. Under Section 202 of UMRA, PHMSA must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with ''Federal mandates'' that might result in expenditures by State, local, and Tribal governments, in the aggregate, or by the private sector, of $100 million (adjusted annually for inflation) or more in any one year (*i.e.,* $153 million in 2016 dollars). This final rule will not result in such expenditure. Accordingly, PHMSA is not required to provide a written statement in accordance with the UMRA.

F. National Environmental Policy Act

PHMSA has analyzed this final rule in accordance with section 102(2)(c) of the National Environmental Policy Act (42 U.S.C. 4332), the Council on Environmental Quality regulations (40 CFR 1500–1508), and DOT Order 5610.1C. PHMSA has published the results of this analysis in an Environmental Assessment (EA) as required by 40 CFR part 1502.

Based on the EA, PHMSA has determined this final rule would not significantly affect the quality of the human environment. To assess the impact of these regulations on the human environment, PHMSA considered three alternative scenarios, including adopting the IFR without amendments, the API RPs as written, and the provisions in this final rule. PHMSA concludes that this action will not significantly affect the quality of the human environment.

To the extent that the measures taken to comply with the IFR did not involve additional environmental impacts and instead served to reduce the risk of natural gas incidents, PHMSA expects this final rule to continue these positive environmental impacts. The information in this Environmental Assessment report supports a Finding of No Significant Impact (FONSI) for this final rule.

G. Executive Order 13132

E.O. 13132 (''Federalism'') (64 FR 43255, Aug. 10, 1999) requires PHMSA to develop an accountable process to ensure ''meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications.'' E.O. 13132 defines policies that have federalism implications to include regulations that have ''substantial direct effects on the states, on the relationship between the national government and the states, or the distribution of power and responsibilities among the various levels of government.''

Section 6 of E.O. 13132 limits regulations that impose substantial direct compliance costs on a State unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by State and local governments. PHMSA also may not issue regulations that preempt State law unless the agency consults with State and local officials early in the process of developing the regulation.

PHMSA has concluded that this action will not have federalism

implications because it does not impose any direct compliance costs on State or local governments. This final rule reduces the burden from information collection and therefore does not impose any direct compliance costs.

With respect to preemption, E.O. 13132 requires agencies to determine if their regulatory actions would preempt State law or impose a substantial direct cost in compliance on them. Congress explicitly addressed the preemption of State underground storage regulations in the PIPES Act in section 60141(e). A State authority may adopt additional or more stringent safety standards for intrastate underground natural gas storage facilities as long as they are compatible with Federal requirements. This statement is consistent with the existing statute governing PHMSA's preemption of State regulation over intrastate pipeline transportation facilities at 49 U.S.C. 60104(c).

As noted in the IFR and the discussion above, interstate facilities would not be subject to any regulatory safety requirements with respect to their wellhead and downhole facilities in the absence of Federal action. Even before the issuance of the IFR, the Federal Pipeline Safety Laws preempted any State regulation purporting to affect interstate pipeline transportation facilities. States with existing underground natural gas storage regulations may continue to implement those additional, and possibly more stringent, regulations on intrastate gas storage facilities to the extent that the State regulations are compatible with the new Federal regulations outlined in this final rule. Interstate underground storage facilities are now subject to the new Federal regulations, whereas previously, those facilities were not subject to any regulatory safety requirements.

H. Executive Order 13175

E.O. 13175 (''Consultation and Coordination with Indian Tribal Governments'') reaffirms the Federal Government's commitment to the Tribal sovereignty, self-determination, and self-government. To that end, the agencies must consult with Tribal governments as they develop policy on issues that may affect those communities. This final rule imposes no substantial direct compliance costs or burdens on Tribal governments. So, the requirements of E.O. 13175 do not apply.

I. Executive Order 13211

E.O. 13211 (''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use'') requires Agencies to prepare a Statement of Energy Effects when undertaking certain actions. Such Statements of Energy Effects shall describe the effects of certain regulatory actions on energy supply, distribution, or use, notably: (i) Any adverse effects on energy supply, distribution, or use (including a shortfall in supply, price increases, and increased use of foreign supplies) should the proposal be implemented, and (ii) reasonable alternatives to the action with adverse energy effects and the expected effects of such alternatives on energy supply, distribution, and use.

In a memorandum on E.O. 13211, OMB outlines the criteria for assessing whether a regulation constitutes a ''significant energy action'' and would have a ''significant adverse effect on the supply, distribution or use of energy.'' [33] Of the potentially adverse effects on the supply, distribution, relevant to this final rule, only one of the criteria is applicable to this final rule: The ability of interstate operators to pass costs on to consumers. However, because this final rule results in cost savings, it would not increase the cost of energy distribution.

J. National Technology Transfer and Advancement Act of 1995

The National Technology Transfer and Advancement Act of 1995, 15 U.S.C. 272, directs Federal agencies to use voluntary consensus standards instead of government-written standards when appropriate. The OMB Circular A–119, ''Federal Participation in the Development and Use of Voluntary Consensus Standards and in Conformity Assessment Activities,'' sets the policy for Federal use and development of voluntary consensus standards. As defined in OMB Circular A–119, voluntary consensus standards are technical standards developed or adopted by domestic and international organizations. These organizations use agreed-upon procedures to update and revise their published standards every three to five years to reflect modern technology and best technical practices.

Accordingly, PHMSA has the responsibility for determining, via petitions or otherwise, which standards it should add, update, revise, or remove from 49 CFR subchapter D. PHMSA handles these changes to incorporate by reference materials via the rulemaking process, which allows the public and regulated entities to provide input. During the rulemaking process, PHMSA must also obtain approval from the Office of the Federal Register to incorporate by reference any new materials.

PHMSA worked to make the materials incorporated by reference reasonably available to interested parties. PHMSA is prohibited from issuing a regulation that incorporates by reference any document unless that document is available to the public, free of charge (Pub. L. 113–30, Aug. 9, 2013).

To meet these requirements, PHMSA negotiated agreements with all but one of the respective standards developing organizations (SDO) with standards already incorporated by reference in the PSRs to make viewable copies of those standards available to the public at no cost. PHMSA has an agreement in place with API, who voluntarily made the RP 1171 and RP 1170 available on API's public website. API's mailing address and the website are listed in 49 CFR part 192.

K. Paperwork Reduction Act

The Paperwork Reduction Act of 1995 [34] (PRA), Public Law 104–13, is implemented by OMB and requires that agencies submit a supporting statement to OMB for any information collection that solicits the same data from more than nine parties. The PRA seeks to ensure that Federal agencies balance their need to collect information with the paperwork burden imposed on the public by the collection.

The definition of ''information collection'' includes activities required by regulations, such as for permit development, monitoring, recordkeeping, and reporting. The term ''burden'' refers to the ''time, effort, or financial resources'' the public expends to provide information to or for a Federal agency or to fulfill statutory or regulatory requirements otherwise. The PRA paperwork burden is measured in terms of annual time and financial resources the public devotes to meet one-time and recurring information requests.[35] Information collection activities may include:

- Reviewing instructions;
- Using technology to collect, process, and disclose information;
- Adjusting existing practices to comply with requirements;
- Searching data sources;
- Completing and reviewing the response; and
- Transmitting or disclosing information.

[33] E.O. 13211 was issued May 18, 2002. The Office of Management and Budget later released an Implementation Guidance memorandum on July 13, 2002.

[34] Substantially amending the PRA of 1980 (Pub. L. 96–511).

[35] 44 U.S.C. 3502(2); 5 CFR 1320.3(b).

Agencies must provide information to OMB on the parties affected, the annual reporting burden, the annualized cost of responding to the information collection, and whether the request significantly affects a substantial number of small entities. An agency may not conduct or sponsor, and a person is not required to respond to, an information collection unless it displays a currently valid OMB control number. OMB has previously approved the information collection requirements contained in IFR under the provisions of the PRA. Since issuing the IFR, PHMSA has estimated changes in reporting and recordkeeping burden and submitted a revised information collection request to OMB for approval. Below is a summary the information collections requested or approved for this final rule.

1. Incident Reporting

PHMSA is finalizing the IFR's revision to 49 CFR 191.15 that requires operators to give notice upon the discovery of incidents meeting the definition at 49 CFR 191.3. Operators must submit DOT Form PHMSA–F7100.2 as soon as practicable but not more than 30 days after they detect the event. On August 16, 2017, OMB approved the use of this form, ''Incident and Annual Reports for Gas Pipeline Operators,'' under Control No. 2137–0522.

2. Safety-Related Conditions Reporting

PHMSA is finalizing the IFR's revision to § 191.23 that requires operators to report a safety-related condition no later than ten working days after its discovery. PHMSA estimates it will receive four annual responses at an annual burden of 24 hours from each operator. This estimate remains unchanged from the IFR's estimate.

On August 16, 2017, OMB approved this information collection, ''Reporting Safety-related conditions on Gas, Hazardous Liquid, and Carbon Dioxide Pipelines, and Liquefied Natural Gas Facilities,'' under Control No. 2137–0578, expiring on August 31, 2019. There is no form dedicated to this information collection. Instead, PHMSA will accept safety-related condition reports in a variety of formats by mail or fax. Instructions for filing are in § 191.25, ''Filing safety-related condition reports.''

3. Annual Reporting

PHMSA is finalizing the IFR's amendment to § 191.17, related to annual reporting. Operators must submit data Form 7100.4–1, ''Underground Natural Gas Storage Annual Report,'' no later than every March 15. The annual report must include data from the previous calendar year. For example, the first annual report was due no later than March 15, 2018, and must have included data from the 2017 calendar year. OMB approved this information collection, ''Incident and Annual Reports for Gas Pipeline Operators,'' on August 16, 2017, under Control No. 2137–0522, expiring on August 31, 2020.

In the IFR, PHMSA estimated a reporting burden of 8 hours to complete each annual report form. That estimate included times for reviewing instructions, gathering the necessary data, and responding to each question. However, PHMSA revised the hourly burden estimate from 8 hours to 20 hours per response based on public comments, which are available for review in Docket No. PHMSA–2016–0016.

4. National Registry of Operators and Notification of Changes

This information collection consists of two parts. The first part requires operators to obtain or validate an Operator Identification Number (OPID) from PHMSA. Under the IFR, PHMSA expected to receive 24 OPID requests and 25 ad hoc notifications. PHMSA estimated that each operator would take 1 hour to complete the OPID Assignment form, PHMSA F 1000.1. PHMSA is making no changes to these estimates in this final rule.

The IFR revised § 191.22 to require operators to notify PHMSA, not less than 60 days prior, of certain events. OMB approved this information collection on July 5, 2017, and it will expire on July 31, 2020. PHMSA estimates that this final rule will result in no additional hourly or cost burdens beyond those estimated in the IFR. PHMSA estimates the combined annual burden for OPID Assignment and Operator Notification at 49 hours. (OMB Control No. 2137–0627).

5. Recordkeeping

As discussed throughout this rulemaking, operators must create and maintain records and in accordance with RP 1170 and RP 1171. Operators must also create and maintain written procedure manuals for integrity and program operations. Because of these requirements in the IFR, and codified in this final rule, 136 entities will be required to keep records. PHMSA estimates that it will take operators approximately 1.6 hours annually to maintain the required records. The cost and hourly burden are based on 136 companies with a loaded labor cost of $88 per hour. OMB approved this information collection under OMB Control No. 2137–0634 on October 11, 2018, and it will expire on October 31, 2021. No additional collection or recordkeeping requirements would be imposed on the public by modifying the requirements of this final rule.

L. Privacy Act

In accordance with the Privacy Act of 1974, 5 U.S.C. 552(a), anyone can search the electronic form of all documents received into any of our dockets by the name of the individual submitting the document (or signing the document, if submitted on behalf of an association, business, labor union, etc.). The complete Privacy Act statement is in the **Federal Register** published on April 11, 2000, (65 FR 19477–78), or at the website: *https://www.transportation.gov/dot-website-privacy-policy.*

M. Regulation Identifier Number (RIN)

A regulation identifier number (RIN) is the unique identifier for each regulatory action listed in the Unified Agenda of Federal Regulations. The Regulatory Information Service Center publishes the Unified Agenda in April and October of each year. Use the RIN number to find this rulemaking in the Unified Agenda. The RIN number for this rulemaking is RIN 2137–AF22.

List of Subjects

49 CFR Part 191

Underground natural gas storage facility reporting requirements.

49 CFR Part 192

Definitions, Incorporation by reference, Underground natural gas storage facility safety.

49 CFR Part 195

National Registry of Operators.

In consideration of the foregoing, PHMSA is amending 49 CFR parts 191, 192, and 195 as follows:

PART 191—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE; ANNUAL REPORTS, INCIDENT REPORTS, AND SAFETY-RELATED CONDITION REPORTS

■ 1. The authority citation for part 191 continues to read as follows:

Authority: 49 U.S.C. 5121, 60102, 60103, 60104, 60108, 60117, 60118, 60124, 60132, and 60141; and 49 CFR 1.97.

■ 2. In § 191.1, revise paragraph (a) to read as follows:

§ 191.1 Scope.

(a) This part prescribes requirements for the reporting of incidents, safety-

related conditions, annual pipeline summary data, National Registry of Operators information, and other miscellaneous conditions by operators of underground natural gas storage facilities and natural gas pipeline facilities located in the United States or Puerto Rico, including underground natural gas storage facilities and pipelines within the limits of the Outer Continental Shelf, as that term is defined in the Outer Continental Shelf Lands Act (43 U.S.C. 1331).

* * * * *

■ 3. In § 191.3, the definitions of ''Incident'' and ''Underground natural gas storage facility'' are revised to read as follows:

§ 191.3 Definitions.

* * * * *

Incident means any of the following events:

(1) An event that involves a release of gas from a pipeline, gas from an underground natural gas storage facility (UNGSF), liquefied natural gas, liquefied petroleum gas, refrigerant gas, or gas from an LNG facility, and that results in one or more of the following consequences:

(i) A death, or personal injury necessitating in-patient hospitalization;

(ii) Estimated property damage of $50,000 or more, including a loss to the operator and others, or both, but excluding the cost of gas lost; or

(iii) Unintentional estimated gas loss of three million cubic feet or more.

(2) An event that results in an emergency shutdown of an LNG facility or a UNGSF. Activation of an emergency shutdown system for reasons other than an actual emergency within the facility does not constitute an incident.

(3) An event that is significant in the judgment of the operator, even though it did not meet the criteria of paragraph (1) or (2) of this definition.

* * * * *

Underground natural gas storage facility (*UNGSF*) means an underground natural gas storage facility or UNGSF as defined in § 192.3 of this chapter.

■ 4. In § 191.15, revise paragraphs (c) and (d) to read as follows:

§ 191.15 Transmission systems; gathering systems; liquefied natural gas facilities; and underground natural gas storage facilities: Incident report.

* * * * *

(c) *Underground natural gas storage facility.* Each operator of a UNGSF must submit DOT Form PHMSA F7100.2 as soon as practicable but not more than 30 days after the detection of an incident required to be reported under § 191.5.

(d) *Supplemental report.* Where additional related information is obtained after an operator submits a report under paragraph (a), (b), or (c) of this section, the operator must make a supplemental report as soon as practicable, with a clear reference by date to the original report.

■ 5. In § 191.17, revise paragraph (c) to read as follows:

§ 191.17 Transmission systems; gathering systems; liquefied natural gas facilities; and underground natural gas storage facilities: Annual report.

* * * * *

(c) *Underground natural gas storage facility.* Each operator of a UNGSF must submit an annual report through DOT Form PHMSA 7100.4–1. This report must be submitted each year, no later than March 15, for the preceding calendar year.

■ 6. Revise § 191.22 to read as follows:

§ 191.22 National Registry of Operators.

(a) *OPID request.* Effective January 1, 2012, each operator of a gas pipeline, gas pipeline facility, UNGSF, LNG plant, or LNG facility must obtain from PHMSA an Operator Identification Number (OPID). An OPID is assigned to an operator for the pipeline, pipeline facility, or pipeline system for which the operator has primary responsibility. To obtain an OPID, an operator must submit an OPID Assignment Request DOT Form PHMSA F 1000.1 through the National Registry of Operators in accordance with § 191.7.

(b) *OPID validation.* An operator who has already been assigned one or more OPIDs by January 1, 2011, must validate the information associated with each OPID through the National Registry of Operators at *https://portal.phmsa.dot.gov,* and correct that information as necessary, no later than June 30, 2012.

(c) *Changes.* Each operator of a gas pipeline, gas pipeline facility, UNGSF, LNG plant, or LNG facility must notify PHMSA electronically through the National Registry of Operators at *https://portal.phmsa.dot.gov* of certain events.

(1) An operator must notify PHMSA of any of the following events not later than 60 days before the event occurs:

(i) Construction of any planned rehabilitation, replacement, modification, upgrade, uprate, or update of a facility, other than a section of line pipe, that costs $10 million or more. If 60-day notice is not feasible because of an emergency, an operator must notify PHMSA as soon as practicable;

(ii) Construction of 10 or more miles of a new pipeline;

(iii) Construction of a new LNG plant, LNG facility, or UNGSF; or

(iv) Maintenance of a UNGSF that involves the plugging or abandonment of a well, or that requires a workover rig and costs $200,000 or more for an individual well, including its wellhead. If 60-days' notice is not feasible due to an emergency, an operator must promptly respond to the emergency and notify PHMSA as soon as practicable.

(2) An operator must notify PHMSA of any of the following events not later than 60 days after the event occurs:

(i) A change in the primary entity responsible (*i.e.,* with an assigned OPID) for managing or administering a safety program required by this part covering pipeline facilities operated under multiple OPIDs;

(ii) A change in the name of the operator;

(iii) A change in the entity (*e.g.,* company, municipality) responsible for an existing pipeline, pipeline segment, pipeline facility, UNGSF, or LNG facility;

(iv) The acquisition or divestiture of 50 or more miles of a pipeline or pipeline system subject to part 192 of this subchapter; or

(v) The acquisition or divestiture of an existing UNGSF, or an LNG plant or LNG facility subject to part 193 of this subchapter.

(d) *Reporting.* An operator must use the OPID issued by PHMSA for all reporting requirements covered under this subchapter and for submissions to the National Pipeline Mapping System.

■ 7. Revise § 191.23 to read as follows:

§ 191.23 Reporting safety-related conditions.

(a) Except as provided in paragraph (b) of this section, each operator shall report in accordance with § 191.25 the existence of any of the following safety-related conditions involving facilities in service:

(1) In the case of a pipeline (other than an LNG facility) that operates at a hoop stress of 20% or more of its specified minimum yield strength, general corrosion that has reduced the wall thickness to less than that required for the maximum allowable operating pressure, and localized corrosion pitting to a degree where leakage might result.

(2) In the case of a UNGSF, general corrosion that has reduced the wall thickness of any metal component to less than that required for the well's maximum operating pressure, or localized corrosion pitting to a degree where leakage might result.

(3) Unintended movement or abnormal loading by environmental causes, such as an earthquake, landslide, or flood, that impairs the serviceability of a pipeline or the

structural integrity or reliability of a UNGSF or LNG facility that contains, controls, or processes gas or LNG.

(4) Any crack or other material defect that impairs the structural integrity or reliability of a UNGSF or an LNG facility that contains, controls, or processes gas or LNG.

(5) Any material defect or physical damage that impairs the serviceability of a pipeline that operates at a hoop stress of 20% or more of its specified minimum yield strength, or the serviceability or the structural integrity of a UNGSF.

(6) Any malfunction or operating error that causes the pressure of a pipeline or underground natural gas storage facility or LNG facility that contains or processes natural gas or LNG to rise above its maximum well operating pressure (or working pressure for LNG facilities) plus the margin (build-up) allowed for operation of pressure limiting or control devices.

(7) A leak in a pipeline, UNGSF, or LNG facility containing or processing gas or LNG that constitutes an emergency.

(8) Inner tank leakage, ineffective insulation, or frost heave that impairs the structural integrity of an LNG storage tank.

(9) Any safety-related condition that could lead to an imminent hazard and causes (either directly or indirectly by remedial action of the operator), for purposes other than abandonment, a 20% or more reduction in operating pressure or shutdown of operation of a pipeline, UNGSF, or an LNG facility that contains or processes gas or LNG.

(10) [Reserved]

(11) Any malfunction or operating error that causes the pressure of a UNGSF using a salt cavern for natural gas storage to fall below its minimum allowable operating pressure, as defined by the facility's State or Federal operating permit or certificate, whichever pressure is higher.

(b) A report is not required for any safety-related condition that—

(1) Exists on a master meter system or a customer-owned service line;

(2) Is an incident or results in an incident before the deadline for filing the safety-related condition report;

(3) Exists on a pipeline (other than an UNGSF or an LNG facility) that is more than 220 yards (200 meters) from any building intended for human occupancy or outdoor place of assembly, except that reports are required for conditions within the right-of-way of an active railroad, paved road, street, or highway; or

(4) Is corrected by repair or replacement in accordance with applicable safety standards before the deadline for filing the safety-related condition report, except that reports are required for conditions under paragraph (a)(1) of this section other than localized corrosion pitting on an effectively coated and cathodically protected pipeline.

(5) Exists on an UNGSF, where a well or wellhead is isolated, allowing the reservoir or cavern and all other components of the facility to continue to operate normally and without pressure restriction.

PART 192—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS

■ 8. The authority citation for part 192 continues to read as follows:

Authority: 49 U.S.C. 5103, 60102, 60104, 60108, 60109, 60110, 60113, 60116, 60118, 60137, and 60141; and 49 CFR 1.97.

■ 9. In § 192.3, revise the definition of ''Underground natural gas storage facility'' to read as follows:

§ 192.3 Definitions.

* * * * *

Underground natural gas storage facility (*UNGSF)* means a gas pipeline facility that stores natural gas underground incidental to the transportation of natural gas, including:

(1)(i) A depleted hydrocarbon reservoir;

(ii) An aquifer reservoir; or

(iii) A solution-mined salt cavern.

(2) In addition to the reservoir or cavern, a UNGSF includes injection, withdrawal, monitoring, and observation wells; wellbores and downhole components; wellheads and associated wellhead piping; wing-valve assemblies that isolate the wellhead from connected piping beyond the wing-valve assemblies; and any other equipment, facility, right-of-way, or building used in the underground storage of natural gas.

* * * * *

■ 10. Republished § 192.7(b)(10) and (11) continue to read as follows:

§ 192.7 What documents are incorporated by reference partly or wholly in this part?

* * * * *

(b) * * *

(10) API Recommended Practice 1170, ''Design and Operation of Solution-mined Salt Caverns Used for Natural Gas Storage,'' First edition, July 2015 (API RP 1170), IBR approved for § 192.12.

(11) API Recommended Practice 1171, ''Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs,'' First edition, September 2015, (API RP 1171), IBR approved for § 192.12.

* * * * *

■ 11. Revise § 192.12 to read as follows:

§ 192.12 Underground natural gas storage facilities.

Underground natural gas storage facilities (UNGSFs), as defined in § 192.3, are not subject to any requirements of this part aside from this section.

(a) *Salt cavern UNGSFs.* (1) Each UNGSF that uses a solution-mined salt cavern for natural gas storage and was constructed after March 13, 2020, must meet all the provisions of API RP 1170 (incorporated by reference, *see* § 192.7), the provisions of section 8 of API RP 1171 (incorporated by reference, *see* § 192.7) that are applicable to the physical characteristics and operations of a solution-mined salt cavern UNGSF, and paragraphs (c) and (d) of this section prior to commencing operations.

(2) Each UNGSF that uses a solution-mined salt cavern for natural gas storage and was constructed between July 18, 2017, and March 13, 2020, must meet all the provisions of API RP 1170 (incorporated by reference, *see* § 192.7) and paragraph (c) of this section prior to commencing operations, and must meet all the provisions of section 8 of API RP 1171 (incorporated by reference, *see* § 192.7) that are applicable to the physical characteristics and operations of a solution-mined salt cavern UNGSF, and paragraph (d) of this section, by March 13, 2021.

(3) Each UNGSF that uses a solution-mined salt cavern for natural gas storage and was constructed on or before July 18, 2017, must meet the provisions of API RP 1170 (incorporated by reference, *see* § 192.7), sections 9, 10, and 11, and paragraph (c) of this section, by January 18, 2018, and must meet all provisions of section 8 of API RP 1171 (incorporated by reference, *see* § 192.7) that are applicable to the physical characteristics and operations of a solution-mined salt cavern UNGSF, and paragraph (d) of this section, by March 13, 2021.

(b) *Depleted hydrocarbon and aquifer reservoir UNGSFs.* (1) Each UNGSF that uses a depleted hydrocarbon reservoir or an aquifer reservoir for natural gas storage and was constructed after July 18, 2017, must meet all provisions of API RP 1171 (incorporated by reference, *see* § 192.7), and paragraphs (c) and (d) of this section, prior to commencing operations.

(2) Each UNGSF that uses a depleted hydrocarbon reservoir or an aquifer reservoir for natural gas storage and was

constructed on or before July 18, 2017, must meet the provisions of API RP 1171 (incorporated by reference, *see* § 192.7), sections 8, 9, 10, and 11, and paragraph (c) of this section, by January 18, 2018, and must meet all provisions of paragraph (d) of this section by March 13, 2021.

(c) *Procedural manuals.* Each operator of a UNGSF must prepare and follow for each facility one or more manuals of written procedures for conducting operations, maintenance, and emergency preparedness and response activities under paragraphs (a) and (b) of this section. Each operator must keep records necessary to administer such procedures and review and update these manuals at intervals not exceeding 15 months, but at least once each calendar year. Each operator must keep the appropriate parts of these manuals accessible at locations where UNGSF work is being performed. Each operator must have written procedures in place before commencing operations or beginning an activity not yet implemented.

(d) *Integrity management program*—(1) *Integrity management program elements.* The integrity management program for each UNGSF under this paragraph (d) must consist, at a minimum, of a framework developed under API RP 1171 (incorporated by reference, *see* § 192.7), section 8 (''Risk Management for Gas Storage Operations''), and that also describes how relevant decisions will be made and by whom. An operator must make continual improvements to the program and its execution. The integrity management program must include the following elements:

(i) A plan for developing and implementing each program element to meet the requirements of this section;

(ii) An outline of the procedures to be developed;

(iii) The roles and responsibilities of UNGSF staff assigned to develop and implement the procedures required by this paragraph (d);

(iv) A plan for how staff will be trained in awareness and application of the procedures required by this paragraph (d);

(v) Timelines for implementing each program element, including the risk analysis and baseline risk assessments; and

(vi) A plan for how to incorporate information gained from experience into the integrity management program on a continuous basis.

(2) *Integrity management baseline risk-assessment intervals.* No later than March 13, 2024, each UNGSF operator must complete the baseline risk assessments of all reservoirs and caverns, and at least 40% of the baseline risk assessments for each of its UNGSF wells (including wellhead assemblies), beginning with the highest-risk wells, as identified by the risk analysis process. No later than March 13, 2027, an operator must complete baseline risk assessments on all its wells (including wellhead assemblies). Operators may use prior risk assessments for a well as a baseline (or part of the baseline) risk assessment in implementing its initial integrity management program, so long as the prior assessments meet the requirements of API RP 1171 (incorporated by reference, *see* § 192.7), section 8, and continue to be relevant and valid for the current operating and environmental conditions. When evaluating prior risk-assessment results, operators must account for the growth and effects of indicated defects since the time the assessment was performed.

(3) *Integrity management re-assessment intervals.* The operator must determine the appropriate interval for risk assessments under API RP 1171 (incorporated by reference, *see* § 192.7), subsection 8.7.1, and this paragraph (d) for each reservoir, cavern, and well, using the results from earlier assessments and updated risk analyses. The re-assessment interval for each reservoir, cavern, and well must not exceed seven years from the date of the baseline assessment for each reservoir, cavern, and well.

(4) *Integrity management procedures and recordkeeping.* Each UNGSF operator must establish and follow written procedures to carry out its integrity management program under API RP 1171 (incorporated by reference, *see* § 192.7), section 8 (''Risk Management for Gas Storage Operations''), and this paragraph (d). The operator must also maintain, for the useful life of the UNGSF, records that demonstrate compliance with the requirements of this paragraph (d). This includes records developed and used in support of any identification, calculation, amendment, modification, justification, deviation, and determination made, and any action taken to implement and evaluate any integrity management program element.

PART 195—TRANSPORTATION OF HAZARDOUS LIQUIDS BY PIPELINE

■ 12. The authority citation for part 195 continues to read as follows:

Authority: 49 U.S.C. 5103, 60102, 60104, 60108, 60109, 60116, 60118, 60132, 60137, and 49 CFR 1.97.

■ 13. In § 195.64:

■ a. Revise the section heading;

■ b. Remove ''National Registry of Pipeline and LNG Operators'' and add ''National Registry of Operators'' in its place everywhere it appears; and

■ c. Remove the website address ''*http://opsweb.phmsa.dot.gov*'' in paragraphs (b) and (c) and add ''*https://portal.phmsa.dot.gov*'' in its place.

The revision reads as follows:

§ 195.64 National Registry of Operators.

* * * * *

Issued in Washington, DC, on January 10, 2020, under authority delegated in 49 CFR 1.97.

Howard R. Elliott,

Administrator.

[FR Doc. 2020–00565 Filed 2–11–20; 8:45 am]

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Ex. I - 4

Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs

API RECOMMENDED PRACTICE 1171
FIRST EDITION, SEPTEMBER 2015

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Foreword

API Recommended Practice 1171 applies to gas storage in depleted hydrocarbon reservoirs and aquifers. Gas storage in solution-mined salt caverns is not addressed, since API 1170 [1] applies to natural gas storage in solution-mined salt caverns.

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Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs

1 Scope

This recommended practice (RP) applies to natural gas storage in depleted oil and gas reservoirs and aquifer reservoirs, and focuses on storage well, reservoir, and fluid management for functional integrity in design, construction, operation, monitoring, maintenance, and documentation practices. The scope does not include pipelines, gas conditioning and liquid handling, compressors, and ancillary facilities associated with storage. Storage design, construction, operation, and maintenance include activities in risk management, site security, safety, emergency preparedness, and procedural documentation and training to embed human and organizational competence in the management of storage facilities. This RP embodies historical knowledge and experience and emphasizes the need for case-by-case and site-specific conditional assessments.

This RP applies to both existing and newly constructed facilities. However, Sections 5 and 7 apply exclusively to new facilities and facilities undergoing expansion, and Section 6 applies to new well construction and remediation of a new or existing well. Figure 1 provides a chart showing the flow of functional integrity assurance activities through the design, operation, and maintenance of storage facilities, with references to the sections within this RP containing guidance for those activities. Applicable distinctions for aquifer facilities are identified within each section as necessary. “Replacement,” as used in this document, refers to the complete replacement of a facility unit, as, for example, when an existing well is abandoned and replaced with a new well. This document recommends that operators manage integrity through monitoring, maintenance, and remediation practices and apply specific integrity assessments on a case-by-case basis.

The contents of this RP are not all inclusive or intended to replace the utilization of detailed information and procedures found in textbooks, manuals, technical papers, or other documents.

This document is intended to supplement, but not replace, applicable local, state, and federal regulations.

2 Normative References

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

API Recommended Practice 5A3, *Recommended Practice on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements*

API Recommended Practice 5C1, *Recommended Practice for Care and Use of Casing and Tubing*

API Technical Report 5C3, *Technical Report on Equations and Calculations for Casing, Tubing, and Line Pipe Used as Casing or Tubing; and Performance Properties Tables for Casing and Tubing*

API Specification 5CT, *Specification for Casing and Tubing*

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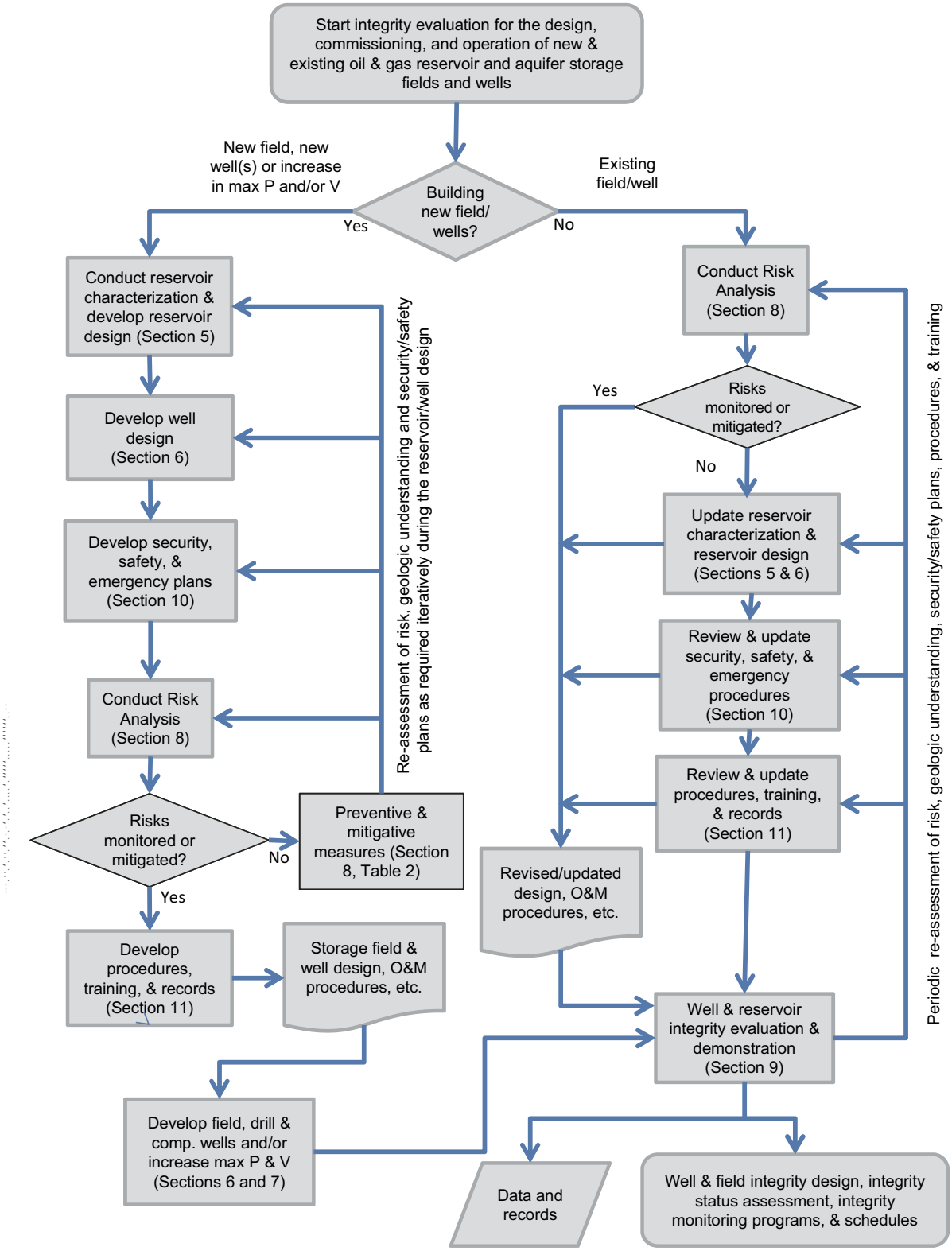

Figure 1—Flow Chart of Document Sections

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3 Terms, Definitions, Acronyms, and Abbreviations

3.1 Terms and Definitions

For the purposes of this document, the following definitions apply. The definitions emphasize the use of the terms in the context of functional integrity.

3.1.1
abnormal operating condition
Condition identified by the operator that may indicate a malfunction of a component or deviation from normal operations that may:

a) indicate a condition exceeding design limits; or

b) result in a hazard(s) to persons, property, or the environment; or

c) indicate a potential downhole problem not related to design or hazard(s) but that may risk the integrity of the well and/or the reservoir.

3.1.2
aquifer pressure
Current pressure in the infinite-acting aquifer attached to an aquifer storage reservoir at a distance not influenced by the storage operation and to which a gas storage reservoir would eventually return if given a long enough shut-in period.

3.1.3
aquifer reservoir storage
Porous and permeable rock media originally filled with water and converted to gas storage.

3.1.4
average (shut-in) reservoir pressure
Pressure of the reservoir based on an average of well pressures in a shut-in condition of no active injection or withdrawal of storage gas.

NOTE Due to the dynamic pressure conditions in a typical gas storage reservoir and/or operational limitations on field shut-in periods, the average reservoir pressure can be extrapolated or assumed based on well pressures from a key indicator well(s) (see **key indicator well**).

3.1.5
basal rock
Rock layer(s) that forms a vertical seal (barrier) to fluid flow at the lower boundary of a storage reservoir.

3.1.6
base gas
[cushion gas]
[pad gas]
Volume of gas needed in a storage reservoir to maintain reservoir pressure to cycle the working storage volume and meet required deliverability rates.

3.1.7
buffer zone
Area or interval outside the defined gas storage reservoir, horizontally and/or vertically, where nonstorage drilling or subsurface operations are restricted to provide protection of the storage reservoir from encroachments and losses.

NOTE Buffer zones accommodate geologic uncertainties in the exact location of the storage reservoir boundaries.

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3.1.8
caprock
Rock layer(s) acting as the vertical seal (barrier) preventing migration of fluids at the upper boundary of the storage reservoir.

3.1.9
caprock threshold displacement pressure
Minimum pressure difference between the gas pressure at the face of the caprock and the water phase pressure immediately above the gas-water interface within the caprock, at which the gas starts to move continuously through the caprock.

3.1.10
cement plug
Cement that is placed in the wellbore with a defined bottom and top to achieve zonal isolation within the wellbore and to prevent communication of fluids between zones by providing a mechanical seal.

3.1.11
collector formation
Formation, usually vertically above the gas storage reservoir, capable of trapping and accumulating gas.

3.1.12
communication
Fluid movement influence, which may be detected by pressure observation, fluid physical and chemical composition analysis techniques, or other means.

3.1.13
containment
Ability of a reservoir to confine stored gas and prevent migration either laterally or vertically out of the reservoir.

3.1.14
contractor personnel
Person or entity utilized by the operator but not directly employed by the operator.

3.1.15
encroachment
Intrusion of a nonstorage well or operations into the defined surface and/or subsurface storage area threatening the integrity of the storage operations.

3.1.16
functional integrity
Total reliability of the storage system, including the physical integrity of the reservoir and well components and the performance reliability assurance established by management systems employed by the storage operator.

3.1.17
groundwater
Subsurface fresh water, potable water, or water that is or can be potentially used as a drinking water supply.

3.1.18
inventory verification
Procedure for confirmation or accounting of total gas present within the storage reservoir at a given time to reconcile with measured volumes and total inventory.

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3.1.19
inventory, total
Total gas volume within the storage reservoir.

NOTE The total inventory at any given time can be determined by an initial determination of gas in place and adjusting that volume for production, fuel, and field use or other losses during production operations; cumulative storage injection and withdrawal activity; and storage operations fuel, field use, or other losses and adjustments.

3.1.20
key indicator well
Shut-in storage well that is representative of the average reservoir pressure of the active gas storage area.

NOTE Key indicator well pressure can be used to develop the pressure-inventory relationship of the gas storage reservoir.

3.1.21
master meter
Gas measurement point(s) in the gas storage facility where accurate gas measurement is made of the full gas flow into or out of the entire storage facility.

3.1.22
maximum cycling capacity
Maximum amount of working gas volume able to be withdrawn and injected over the time of a complete design cycle from maximum to minimum pressures within the reservoir.

3.1.23
maximum reservoir pressure
Average stabilized shut-in reservoir pressure at maximum design capacity of gas in storage.

3.1.24
mechanical integrity
Quality or condition of a well in being structurally sound with competent pressure seals by application of technical, operational, and organizational solutions that reduce the risk of uncontrolled release of formation fluids throughout the well life cycle.

3.1.25
mechanical integrity test
Procedure that obtains data that demonstrates if a well is mechanically fit for service and capable of storing natural gas within design limitations.

3.1.26
minimum reservoir pressure
Average stabilized shut-in reservoir pressure at minimum design capacity of gas in storage.

3.1.27
native gas
Unproduced gas indigenous to the reservoir that remains in the reservoir at the time of conversion to storage.

3.1.28
observation well
Well that functions as a pressure and fluid monitoring point, located within, above or below, or laterally adjacent to the active storage reservoir, and generally not used to inject or withdraw storage gas.

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3.1.29
plan
Documented explanation of the mechanisms or procedures used to implement a program and to achieve compliance with standards.

NOTE A specific well work plan for drilling, completion, servicing, or workover operations can be written step-by-step instructions and associated information (cautions, notes, warnings) that describe how to safely perform a task.

3.1.30
pound-days
Empirical method of estimating the aquifer response to gas injection and withdrawal cycling.

NOTE 1 Net pound-days are calculated by summing the differences in daily reservoir pressure, in pounds per square inch, above (plus) or below (negative) the aquifer pressure over the period of an injection and withdrawal cycle.

NOTE 2 The pound-days calculation can be used in hydrocarbon reservoir storage applications as well as aquifer reservoir storage applications.

3.1.31
pressure cycling
Cyclic variations in reservoir pressure due to the injection and withdrawal of gas.

NOTE In reservoir gas storage operations, pressure cycling often occurs over a one-year period with injections in the summer and withdrawals in the winter; however, storage operations may involve any number, timing, and amplitude of pressure cycles.

3.1.32
pressure-inventory relationship
Correlation between reservoir pressure and total gas inventory over time.

NOTE The data to trend the relationship can be derived from well pressure observations and total inventory.

3.1.33
procedure
Documented explanation of action taken to achieve the steps of a process.

NOTE Procedures can be a description of the execution of tasks in a method or linked set of methods that will enable the activity to be accomplished according to a set of guidelines and standards.

3.1.34
process
Systematic, ordered series of events directed to some end that comprise an approach or methodology to achieve an objective

NOTE A process can describe work flow activity and quality standards for a wide range of procedures.

EXAMPLE The risk management process is a systematic application of management policies, procedures, and practices to the activities of communicating, consulting, establishing the context, and identifying, evaluating, monitoring, and reviewing risk.

3.1.35
program
Overall approach to manage a functional activity or physical part of an asset.

NOTE A program can be a defined outline of work activities that are designed to address specific objectives. Programs identify what to do and why it needs to be done. The program can define important aspects such as purpose and scope, roles and responsibilities, tasks and procedures, and anticipated results and work products.

3.1.36
spill point
Point or area in a hydrocarbon trap at which the trap can be breached.

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NOTE The spill point may be related to geologic structure, permeability, fluid density, pressure, and viscosity, or any combination of those features.

3.1.37
wellhead
Surface equipment used to maintain control of the well, including the connecting casing head, tubing head, and Christmas tree.

3.1.38
working gas
[top gas]
[current gas]
Volume of gas in the reservoir above the designed level of base gas.

3.1.39
zonal isolation
Condition of no communication between the gas storage formation and other formations in a wellbore or between the wellbore and any formation intended to be isolated.

3.2 Acronyms and Abbreviations

For the purposes of this document, the following acronyms and abbreviations apply.

H_2S	hydrogen sulfide
MOC	management of change
O&M	operations and maintenance
pH	hydrogen ion potential
P&M	preventive and mitigative
Tcf	trillion cubic feet

4 General Principles of Underground Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs

4.1 General

This section provides general background into the functions, history, and geotechnical aspects of underground natural gas storage.

4.2 Functions of Underground Natural Gas Storage

Natural gas storage utilizes depleted hydrocarbon and aquifer reservoirs selectively located where geology is suitable. The natural gas storage reservoirs are connected into the natural gas infrastructure via pipelines. Residential and commercial heating and cooling, value arbitrage, swing service between pipelines, and load-following service to electric generation create fluctuations in gas demand. The fluctuations in natural gas demand versus the relative consistency of natural gas supply are managed by underground natural gas storage. Underground natural gas storage facilities function to smooth out the disparity between supply and demand during these peak demand periods. Without storage, serving demand fluctuations would require wide swings in the sources of gas supply, which could negatively impact ultimate gas recovery. Furthermore, without the integration of storage facilities into the pipeline system, the capacity of the pipeline network would need to be much greater to accommodate the highest flow rates to the markets during peak demand periods. Gas supply and transportation can be more efficient with storage available to the pipeline system.

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4.3 History of Underground Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs

Natural gas has been stored underground in depleted hydrocarbon reservoirs in the United States since 1916 when the Zoar Field in western New York was first used for storage. As of 2015, there are more than 350 active gas storage reservoirs in the United States and Canada using depleted hydrocarbon reservoirs. These facilities represent over 16,000 reservoir-years of operation (i.e. sum of operating years of each of the 350 reservoirs), store over 7.8 Tcf of natural gas at maximum capacity, and are accessed and monitored by more than 14,200 wells.

Aquifer reservoir storage dates back to 1946. As of 2015, there are 51 operating aquifer storage reservoirs in the United States and Canada representing over 2,300 reservoir-years of operation, with a maximum inventory capacity of 1.3 Tcf, accessed and monitored by more than 2,600 wells.

4.4 Geotechnical Aspects of Underground Natural Gas Storage

Natural gas is stored underground in areas where porous and permeable rock is available and can contain the injected natural gas. Underground porous zones are typically fluid-filled in their native state and the fluid can be hydrocarbons (oil, gas) and/or water. Once the hydrocarbons are depleted, the porous zone can be used for natural gas storage. Alternatively, the porous zone may be filled with only water, which does not necessarily require any depletion before it can be converted for use as a natural gas storage reservoir. It is also possible to excavate or solution-mine caverns into otherwise impermeable rock for the storage of gases and liquids. API 1170 applies to natural gas storage in solution-mined salt caverns.

Depleted hydrocarbon reservoirs are candidates for natural gas storage because the reservoir integrity has been demonstrated over geologic time by hydrocarbon containment at initial pressure conditions. Depleted hydrocarbon reservoirs generally have available rock data, reservoir engineering data, and fluid compositional data from their production history. The storage suitability of a hydrocarbon reservoir requires investigation on an individual basis, using a number of means to evaluate reservoir integrity, well integrity and fluid chemistry.

In regions where depleted hydrocarbon reservoirs are not present, aquifers exhibiting the qualities of a hydrocarbon reservoir may be available. Aquifer reservoirs are similar to depleted hydrocarbon reservoirs in terms of the nature of the porous rock media used to contain the gas and the methodology for assessing the reservoir. The storage suitability of an aquifer reservoir requires investigation on an individual basis, using a number of means to evaluate reservoir integrity, well integrity, and fluid chemistry.

There is no ideal depth, rock type, or trapping mechanism; each reservoir requires site-specific evaluation. The gas trapping mechanism depends on rock porosity and permeability controls, hydrodynamics, and geologic structural controls. The top of the reservoir is sealed by impervious rock referred to as its “caprock.” The bottom of the reservoir and lateral boundaries are sealed by structural closure, decrease or loss of porosity and permeability, or hydrodynamic forces. The containment of stored gas can be managed by means of facility and operational controls when geologic boundaries are less than ideal.

Gas storage reservoirs are monitored over their operating lifetime to evaluate functional integrity and management of gas containment. Monitoring includes protecting the reservoir from potential integrity threats brought on by third-party drilling, hydrocarbon production, and mining operations.

The reservoir is accessed via wells drilled either vertically or directionally from the surface. The wells are connected to a surface pipeline network that transports the gas to and from a central station, where gas separation, dehydration, metering, and compression facilities are commonly located. New gas storage wells are constructed for a long useful life to withstand cyclic pressure and temperature conditions. Existing wells used in storage operations undergo mechanical integrity evaluations prior to conversion to ensure safety under storage operating conditions. Gas storage wells are monitored and maintained over their operating lifetime to evaluate the containment capability of the fluids at the pressures and flow rates expected.

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5 Functional Integrity in the Design of Natural Gas Storage Reservoirs

5.1 General

This section addresses the requirements for the assessment and design of new natural gas storage capacity development in hydrocarbon production reservoirs and aquifer reservoirs, and increased maximum pressure and/or total capacity in existing natural gas storage reservoirs. The assessment steps are arranged generally in order of increasing effort and resources, beginning with utilization of available data and progressing to data gathering and testing.

5.2 Geological Reservoir Characterization

5.2.1 General

The goal of the baseline geological reservoir characterization is to develop a practical understanding of the suitability of the reservoir and the adjacent geologic stratigraphic environment prior to storage development or expansion.

5.2.2 Geological Characterization

A preliminary evaluation of the extent and properties of the porous rock interval, or reservoir, intended for storing natural gas, and the confinement mechanisms to contain the hydrocarbon accumulation in the reservoir, shall be conducted, characterized, and presented in the form of geologic mapping and analysis. The geologic characterization uses available data, which can be obtained from various sources, including published literature, regulatory agencies, production operators, academic institutions, and commercial data providers, to provide a basis that can be refined by engineering reservoir characterization and supplemental data gathering.

The geologic characterization shall be used to establish the initial vertical and areal buffer zone in order to protect the integrity of the natural gas storage operation. Once a reservoir is in operation, the findings of ongoing reservoir performance monitoring programs may require that the buffer zone be reviewed and revised as necessary to protect and maintain the integrity of the storage reservoir.

The scope of the geologic characterization should encompass the intended reservoir rock and sealing mechanisms, the vertical interval above and below the intended reservoir, areas where gas could potentially migrate, and the areas adjacent to the intended reservoir where potential entrapment of migrated gas could occur. The depths of groundwater and locations of surface waters should be delineated. Locations of abandoned wells, underground disposal horizons, mining, and other industrial activities should be mapped. Surface topography and land use should be included in the evaluation where topography and land use may impact storage surface facilities and/or subsurface integrity.

The reservoir rock itself should be characterized including its lithology, geo-mechanical competency, porosity, permeability, homogeneity, isotropy, and residual pore fluid saturations. Reservoirs that have proven suitable for natural gas storage include structural and stratigraphic entrapments within porous and permeable rock, which could have a connection to a regional aquifer, or a hydrodynamic entrapment in a structural feature within a regional aquifer. A competent and impermeable caprock, located above the intended gas-filled reservoir, should be identified and evaluated for controlling the upward movement of the stored natural gas. The basal and lateral sealing mechanisms should be identified and evaluated for controlling movement of the stored gas.

Available data such as drilling data, logs, fluid samples, cuttings and core data from existing hydrocarbon and water wells, or other geophysical data such as seismic, gravity, and magnetic surveys should be used for the geological characterization. The quantity and quality of data used in the geologic characterization should be evaluated throughout the design phase to determine the need for supplemental data gathering, either prior to or during construction. The design should address alternative geological characterizations that are consistent with the data, and plans for mitigating integrity issues associated with potential alternative interpretations.

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Anomalous geologic features should be evaluated in terms of their potential for compromising reservoir integrity with respect to the containment of stored gas. Such features may include faulting, natural fracturing, folding, and unconformities.

5.3 Engineering Reservoir Characterization

5.3.1 General

The engineering characterization expands upon the geological characterization. The goal is to understand, prior to storage development or expansion, the probable response of the reservoir and adjacent areas to the proposed pressure cycling and flow rates.

5.3.2 Engineering Characterization

The scope of the engineering reservoir characterization should incorporate the vertical and areal bounds of the geological characterization, and include examination of any anomalous geological features, if possible. The engineering characterization may suggest that the scope of the geologic characterization should be modified or expanded.

The engineering characterization should include a review of records for all existing and abandoned wells that penetrate the formations being characterized. Existing wellbore and wellhead records should be reviewed to evaluate their current mechanical integrity in order to verify suitability for the intended design and protection of reservoir integrity. At a minimum, casing materials, casing configuration, casing set depths, cement materials, and placement depths shall be evaluated for effective mechanical integrity. Plugged and abandoned wells should be evaluated to determine if the plugging practices, and plugging materials utilized and the placement of the plugs, effectively prevent fluid migration. Section 6 provides guidance with regard to recommended well characteristics.

Reservoir pore fluid chemistry and physical properties should be characterized, particularly in gas-liquid and oil production reservoirs and in reservoirs containing impurities exceeding pipeline gas quality specifications. The chemical and physical properties of pore water should be characterized, particularly for aquifer reservoirs intended for natural gas storage. Corrosive potential of the pore fluids shall be determined and corrosion management shall be incorporated into design and operation strategies. Potential mineralogical and fluid compatibility issues with anticipated drilling or treating chemicals and liquid mixtures shall be identified and mitigated.

Engineering data for the characterization of hydrocarbon reservoirs should include completion and production records for the target reservoir. Records from vertically and laterally offset well completion, stimulation, and production operations within the geological characterization zone described in 5.2 should be reviewed. At a minimum, initial and current reservoir pressure shall be identified. For existing storage fields being considered for expansion, prior gas storage operational records should be analyzed in order to evaluate the interaction of the gas storage operation with the rock-fluid system of the reservoir. For aquifer reservoirs, available water well test data should be analyzed. The quantity and quality of available data used in the engineering characterization should be evaluated to determine the need for supplemental data gathering, either prior to or during construction. The design should address alternative engineering characterizations that are consistent with the data, and plans for mitigating integrity issues associated with potential alternatives.

Anomalous locations of hydrocarbons or pressure found in the historic data review can indicate mechanical integrity issues related to existing wells, or that the reservoir characterization is inaccurate. Potential mechanical integrity issues should be identified for further investigation as appropriate.

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5.4 Containment Assurance of Reservoir Design

5.4.1 General

Data shall be acquired to provide the design necessary to eliminate or manage uncertainties identified by the geologic and engineering reservoir characterization. The operator shall assess containment capability of the reservoir and the wells for the design storage operation volumes, pressure, and rates of withdrawal and injection. The quantity and quality of data used in the containment assurance analysis should be evaluated to determine the need for supplemental data gathering, either prior to or during construction. The design should address alternative characterizations that are consistent with the data, and plans for mitigating integrity issues associated with potential alternatives.

5.4.2 Reservoir Connectivity

In cases where connectivity with another porous zone is indicated but can be accommodated without loss of functional integrity, the design shall address the gas migration control and containment risk mitigation methodology, such as gas recovery, pressure limitations, zonal control, and expansion of the vertical and lateral dimensions of the buffer zone.

5.4.3 Maximum and Minimum Pressure

The operator shall document the design basis for maximum reservoir pressure.

NOTE The design basis can employ analysis of fracture gradient, water gradient, initial pressure, caprock permeability, caprock threshold displacement pressure, geo-mechanical testing, or other means.

The pressure required to inject intended gas volumes, particularly at total inventory, shall not exceed the design pressure limits of the reservoir, wells, wellheads, piping, or associated facilities.

The minimum reservoir pressure should not be designed less than historic minimum operated pressure unless reservoir geo-mechanical competency can be demonstrated. The impacts of intended minimum reservoir pressure should be accounted for in a regional review of the geologic horizon as it relates to geo-mechanical stress, reservoir liquid influx, surface facility gas cleaning and liquid handling, and liquid disposal, all of which affect the maximum cycling capacity of the storage field and can impact mechanical integrity of the facilities. The minimum reservoir pressure determination can include supplemental well drilling, coring, and laboratory analyses to provide data for the evaluation.

5.4.4 Well Penetrations

Wells completed in or penetrating through the intended storage reservoir, caprock, and basal rock shall be evaluated for containment assurance for the design storage operation volumes, pressure, and flow rates. The operator should identify wells that may require integrity testing and/or well logging in order to meet the integrity demonstration requirements of 7.2. Selected plugged wells may be re-entered, examined, and replugged or monitored to manage identified containment assurance issues.

5.4.5 Supplemental Evaluation

Supplemental reservoir geological and engineering evaluation shall be required for the delineation of potential reservoirs to be developed within aquifers. Characterization of the potential extent of the aquifer and its potential or probable influence on the storage reservoir operation should be determined. Well drilling, logging, and coring shall be performed to gather data and analyze characteristics of the reservoir, caprock, basal rock, and lateral seals. Site-specific geophysical delineation shall be performed, including drilling of test wells and observation wells, and identification of reservoir closure, spill points, and vertical containment. Water pump testing and water level

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observation shall be performed in order to characterize reservoir dimensions, gas capacity, flow performance, and caprock integrity.

Supplemental geological characterization may be performed for hydrocarbon reservoirs having a minimal amount of existing and available geologic data or if undrilled potential entrapments are indicated nearby from the initial evaluations. Additional targeted geophysical surveying or geologic data collection may be obtained.

5.4.6 Other Design Factors

Design factors to protect the mechanical integrity of the storage facilities should include:

a) analysis of facility flow erosion, hydrate potential, individual facility component capacity and fluid disposal capability at intended gas and liquid rates and pressures; and

b) analysis of the specific impacts that the intended operating pressure range could have on the corrosive potential of fluids in the system.

5.4.7 Facility Integrity Plan

The operator should develop a facility integrity plan that covers the storage facility. The facility integrity plan documents work performed during a containment assurance analysis detailed in this subsection, identifies required integrity work and implementation schedule during and after construction, identifies integrity monitoring required during commissioning as detailed in Section 7, and identifies operations monitoring requirements detailed in Section 9 and Section 11.

NOTE The facility integrity plan can be in the form of a standard plan used by the operator for multiple natural gas storage facilities or a site-specific plan.

5.5 Environmental, Safety, and Health Considerations in Design

5.5.1 Design and Construction Safeguards

Safeguards to the environment, safety, and health of workers and the public shall be incorporated into natural gas storage design.

NOTE Publications such as API 51R [2] and API 76 [3] can be referenced to identify safeguards for application in natural gas storage design.

The operator shall incorporate protection of surface water and groundwater resources in the design of storage facilities. The operator should conduct an environmental impact review prior to well drilling and facility construction.

The design of natural gas storage facilities shall incorporate plans for monitoring worksite conditions related to storage development and well drilling in order to protect the environment and the safety and health of workers and the public.

5.5.2 Operation and Maintenance Safeguards

The operator should design for long-term viability and functional integrity of the storage facility in order to promote the ability to maintain and operate the storage facility consistent with environmental regulations and to maintain worker and public safety throughout the life of the storage facility.

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5.6 Recordkeeping

Accurate and comprehensive records of natural gas storage design activities shall be maintained for the life of the facility. The records shall include, as applicable and available:

— geologic records such as well logs, cuttings reports, core reports, geophysical records, and maps;

— engineering records such as historic hydrocarbon production data, data gathered during aquifer and hydrocarbon reservoir characterization, reservoir design data, and gas storage reservoir operational data;

— documents related to storage land and mineral ownership, rights, and control;

— facility integrity plan;

— well drilling, completion, workover, and plugging records for wells analyzed for the design and for proposed well actions during project construction; and

— regulatory records including permit applications, permits, reports, and correspondence.

6 Functional Integrity in the Design and Construction of Natural Gas Storage Wells

6.1 General

This section addresses the requirements for functional integrity in the design, construction, and completion of new natural gas storage wells, the remediation and reconditioning of existing wells, and abandonment of wells within a natural gas storage facility.

6.2 Wellhead Equipment and Valves

6.2.1 General

New or replacement wellhead equipment, including associated fittings, flanges, and valves, should conform to API 6A [4].

6.2.2 Wellhead Equipment Design

New and replacement wellheads shall allow for full-diameter entry to the wellbore. As part of the planning for well maintenance, the operator shall review the well records to determine if limited or less-than-full-diameter access situations are sufficient to allow for the planned activities.

A well shall be equipped with valves to provide isolation of the well from the pipeline system and to allow for entry into the well.

NOTE The pipeline isolation valve, as defined by the operator, can be a pipeline jurisdictional or regulated valve.

EXAMPLE In the United States, the requirements for the pipeline isolation valve are defined in 49 *CFR* 192.145 [5].

All ports on the wellhead assembly above the casing bowl should be equipped with valves, blind flanges, or similar equipment.

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6.2.3 Pressure Rating

Wellhead equipment shall have operating pressure ratings sufficient to exceed the maximum anticipated operating pressure. In addition, the wellhead design should include evaluation of the following:

— treating and stimulation pressures;

— flow rates;

— fluid chemical composition of produced fluids and fluids used in well stimulation;

— possible solids production;

— possible increases in the maximum operating pressure;

— intended flow path; and

— accommodation for pressure and/or temperature monitoring of tubular and annular spaces.

6.2.4 Existing Equipment

Existing wellhead equipment is accepted if it has demonstrated containment of maximum operating pressure, but shall be further evaluated for suitability before increasing the operating pressure beyond the historical maximum.

6.2.5 Emergency Shutdown Valves

Automatic or remote-actuated emergency shutdown valves (wellhead, side-gate, or subsurface) are not required for most storage wells; however, the operator shall evaluate the need for any type of emergency shutdown valve by reviewing the following:

— distance from dwellings, other buildings intended for human occupancy, or other well-defined outside areas where people assemble such as campgrounds, recreational areas, or playgrounds;

— gas composition, total fluid flow, and maximum flow potential;

— distance between wellheads or between a wellhead and other facilities, and access availability for drilling and service rigs and emergency services;

— added risks created by installation and servicing requirements of safety valves;

— risk to and from the well related to roadways, rights of way, railways, airports, and industrial facilities;

— alternative protection measures that could be afforded by barricades or distance or other measures; and

— present and predicted development of the surrounding area, topography, and regional drainage systems and environmental considerations.

NOTE API 14A [6] and API 14B [7] provide guidance (for design, installation, and testing) when a subsurface safety valve is used. Testing of safety valves is discussed in 9.3.

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6.3 Well Casing

6.3.1 General

A well shall be completed with two or more strings of casing as needed to:

— protect groundwater;

— control wellbore conditions;

— isolate the storage gas within the storage reservoir; and

— inject storage gas from the pipeline into and withdraw out of the storage reservoir to the pipeline.

Each string of casing shall be designed in accordance with API 5C3 in order to safely contain the internal casing pressures and withstand the external casing (formation) pressures through the setting depth. The operator should determine its own guidelines for establishing safety factors for use with API 5C3 calculations, recognizing minimum design safety factors that may be dictated by applicable regulations.

6.3.2 Conductor Casing

The conductor casing should be of sufficient size and grade to support subsequent drilling operations.

6.3.3 Surface Casing

The surface casing shall be of sufficient size, grade, and depth to support subsequent drilling operations and to protect groundwater.

NOTE When, due to geologic conditions, a supplemental string of casing is necessary before the surface casing point is reached, the supplemental casing is considered an intermediate casing string for purposes of this standard.

6.3.4 Intermediate Casing

A well may have one or more intermediate strings of casing as needed to maintain control of subsurface conditions and to support subsequent drilling operations. Placement may be stipulated by applicable regulations.

6.3.5 Production Casing

The production casing, which provides access to the storage interval, shall be of adequate size and strength to maintain the well integrity and be compatible with fluid chemical composition.

The production casing should be designed to accommodate fluids on injection and withdrawal at the maximum expected pressures and velocities.

NOTE API 14E [8] provides guidance for velocity calculations and limitations.

The production casing shall be free of open perforations or holes other than the planned completion interval(s). Perforations created for investigative or remedial work shall be sealed to establish hydraulic isolation.

6.3.6 Handling

Casing shall be stored, transported, lifted and installed as specified by the manufacturer and in accordance with API 5C1.

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6.3.7 Connections

Casing connections shall be designed to accommodate loads associated with placement. The operator should calculate the expected mechanical load conditions for casing in the vertical and/or directionally oriented conditions during running, cementing, drilling, and operations and design the casing to have mechanical properties in excess of the mechanical load conditions. The casing shall maintain a gas seal under anticipated wellbore flow conditions and subsequent work in the wellbore (drilling, stimulation, and remediation).

Casing connections shall be made up according to manufacturer specifications or in accordance with API 5CT.

Thread compound or lubricant shall be compatible with the expected wellbore environment and shall be consistent with the manufacturer's recommended lubricant or API 5A3.

6.4 Casing Cementing Practices

6.4.1 General

The purpose of cement in the construction of a new or reworked natural gas storage well is to maintain the integrity of the storage reservoir by providing isolation of the reservoir from communication with other sources of permeability or porosity through the drilled wellbore. In new construction, isolation is accomplished by filling the annular space between the casing and formation with competent cement to create a seal so that communication of fluids between the wellbore and the storage zone or other zones of interest is prevented.

6.4.2 Cement Quality

Cement should meet quality standards in API 10A [9] and ASTM C150/C150M [10] or exceed the requirements set in these standards.

6.4.3 Cement in Well Construction and Remedial Work

Properly designed and placed cement has several important functions in the construction, remediation, and plugging of gas storage wells to provide wellbore and reservoir integrity.

Conductor Pipe—When conductor pipe is placed in a drilled hole, the operator should cement the pipe in place, and the cement slurry should be designed for sufficient volume to circulate the cement to the surface.

NOTE Driven conductor pipe does not require cementing.

Surface Casing—The cement slurry design should provide for a volume in excess of the annular volume and, if technically feasible, with sufficient volume to circulate the cement to the surface to provide support for the wellhead and casing strings and isolate groundwater from communication with fluids from other sources.

Intermediate Casing—The operator should use cement slurry designed for the anticipated wellbore conditions. Cement should be designed for sufficient volume to circulate the cement to the surface when possible. Where it is not possible to circulate cement to surface, the operator should design the cementing program such that the cement top would be at a point within the surface casing to establish zonal isolation.

Production Casing and Liners—The operator shall use cement slurry or slurry combinations designed for hydrostatic weight control and strength requirements. The production casing cement should be designed for sufficient volume to:

— circulate the cement to the surface, or

— circulate to a point within the next casing string, or

— establish the zonal isolation of permeable zones.

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Cement slurry used for cement plugs can be relatively small in volume and be subject to contamination by wellbore fluids; operators should design plug slurry composition and plug setting techniques to minimize the chance for contamination, as such contamination could result in weak, diluted, nonuniform, or unset cement plugs. Cement slurry for plugs should be designed for both cement blend and placement to have mechanical and isolation properties for the proposed use and functional objectives.

Remedial cementing procedures are used to squeeze cement outside of the casing in order to restore wellbore integrity, seal off communicating zones, or to provide zonal isolation. The operator should design the remedial cement slurry and placement technique for the specific wellbore conditions, formations, and type of repairs, such that isolation of the storage zone from all other sources of porosity and permeability is achieved.

6.4.4 Cement Slurry Design and Controls

A successful cement job is designed for the specific conditions of each well with controls established to enable the cement slurry to perform as designed. When designing a cement slurry, the operator should review information such as the historical success of cement slurry composition at achieving isolation objectives in nearby wells, the type of formations, temperature, and requirements such as water ratio, desired compressive strength, prevention of contamination by formation fluids, and various additives to control fluid rheology and reaction time.

NOTE 1 Conditions can exist that require special evaluation in the design of the cement such as highly porous formations, salt formations, coal formations, mine voids, corrosive formations, washouts, multi-stage cementing, or intermediate casing strings.

The equivalent circulating density of the cement pumping operation shall be designed such that the fracture gradient of the storage zone is not exceeded and such that lost circulation potential of any exposed zone is minimized.

Cement volumes in excess of the calculated or measured requirement may be used when required to circulate cement to surface.

NOTE 2 Caliper logging can provide information to improve casing-borehole annular volume calculation when wellbore caving or enlargement is suspected.

Laboratory testing may be conducted to confirm that the cement blend meets design requirements.

Each source of mix water may be tested for pH and temperature prior to mixing to confirm that the cement blend meets design requirements.

Representative slurry samples should be obtained from each cement blend pumped and held for further analysis.

The cement cure time should be determined and time should be allowed for the cement to develop compressive strength before the casing is disturbed or differential stress is placed upon the casing.

6.4.5 Cement Pumping Design

The proper placement of the cement slurry provides well integrity by isolating the reservoir from communication with other sources of potential fluid flow.

Prior to cementing a casing string, the operator should condition the fluid in the wellbore to improve the fluid mobility, assist in fluid displacement by the cement slurry, and achieve good cement bonding with the casing and formation.

NOTE 1 API 65-2 [11] provides guidance on conditioning the fluid in the wellbore.

The operator should use spacers and/or preflushes to help remove any mud cake that may exist. The spacers should isolate dissimilar fluids to prevent potential cement contamination problems.

NOTE 2 The spacers and preflushes are often weighted to prevent fluid entry during the precementing cleaning process.

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The casing should be centralized in the wellbore to prevent cement channeling, especially in and near zones where good cement bonding is critical. The impact of wellbore inclination should be evaluated when designing the placement and spacing of centralizers. The operator should address geologic conditions and hole deviation conditions that require additional evaluations for casing centralization design.

NOTE 3 Casing centralization aids in the removal of drilling fluids behind the pipe during the cement slurry pumping process and thereby improves the uniform flow of cement up the annulus. API 10D-2 [12] and API 10TR4 [13] provide guidance. Cementing service company technical experts provide guidance and recommendations.

Where known formation and wellbore conditions present a risk to zonal isolation through cementing practices alone, the operator may use external casing packers or other isolation equipment in the design of the cement job.

A guide shoe should be installed on the first joint of the production casing to avoid ledges, prevent sidewall caving, and prevent damage to the bottom of the casing while running the casing in the well.

A float collar or other equivalent device should be installed one or more pipe joints from the bottom of the casing to prevent backflow, reduce derrick stress, and prevent contaminated cement from reaching the shoe.

Competent, uncontaminated cement shall be placed around the casing shoe and around the circumference of the casing in order to meet the requirements of 6.4.3.

A wiper or cementing plug should be used during the cementing of the production casing to reduce the potential for contamination of the cement and help control displacement volumes.

When feasible, pipe movement (i.e. either rotation or reciprocation of the casing) during hole conditioning and cement pumping should be employed to help eliminate the possibility of cement channeling. After pumping, there should be no pipe movement or disturbance until the cement has been allowed to develop initial compressive strength.

NOTE 4 Casing scratchers can promote cement bonding by assisting in mud cake removal when using pipe movement.

Cement pumping and mixing equipment should be appropriate for the pressures and rates required for the job and should be capable of providing a continuous pumping operation at the designed rates and control slurry density. Backup equipment should be available in order to address possible pumping equipment failures while circulating the cement.

6.4.6 Cement Evaluation and Location

Evaluation of cement placement and quality is done to determine that a competent seal exists to prevent the communication of fluids from the storage zone or other zones of interest.

The location and quality of the cement bond or seal between the production casing, or liner if applicable, and formation shall be evaluated to determine whether adequate formation and pipe bonding has been achieved to prevent the migration of gas and fluids between zones.

NOTE 1 It is important that cement bonding is present across the caprock of the storage zone to maintain the mechanical integrity of the well and protect the storage reservoir.

Cement placement and bond quality shall be evaluated with a cement bond log or other means that can demonstrate the sealing potential of the cement. The evaluation should not take place until the cement cure time determined in the cement design has allowed the cement to reach a sufficient compressive strength for accurate interpretation of the log or method being used.

NOTE 2 API 10TR1 [14] provides principles and practices regarding the evaluation of primary cementation of casing strings in oil and gas wells.

NOTE 3 Radial cement bond logs help to identify cement channeling that can impair zonal isolation.

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NOTE 4 A temperature log run in the first 12 to 24 hours after cementing assists in locating the approximate top of the cement, but does not indicate the quality or bonding of the cement to the casing and borehole wall surfaces.

The operator should observe the well's annuli after cementing operations to determine that no annular flow or other evidence of containment issues exist.

A mechanical integrity test (see 6.9) of each casing string should be completed prior to drilling out or perforating.

6.5 Completion and Stimulation

6.5.1 General

The operator shall design and conduct well completion and stimulation operations to verify that pressure, flow rates, and other mechanical conditions have no adverse impact on the storage reservoir, caprock, or the mechanical integrity of the well.

The operator should review casing and wellhead design and installation parameters, workover history, and previous mechanical integrity tests to verify that stimulation and completion loads do not exceed the pressure limits and safety factors, which could result in a failure of the well's mechanical integrity.

6.5.2 Baseline Logging

The operator should run a cased-hole formation log to correlate with the baseline formation log prior to completion and/or stimulation treatments in order to verify the location of the production casing and casing collars relative to the formations traversed by the well.

6.5.3 Fracture Stimulation

When a fracture treatment is applied, it shall be conducted in a manner such that the fracture height or length does not compromise the integrity of the storage reservoir.

The operator should follow API fracturing guidance documents: API HF1 [15], API HF2 [16], and API HF3 [17].

The operator should monitor wells and the reservoir after fracture treatment of a well at an increased frequency for abnormal conditions that could indicate a loss of integrity. Monitoring may include:

— annulus pressure or flow at the fracture-treated well and at nearby wells;

— pressure and unusual pressure changes in the fracture-treated well and in nearby wells;

— fluid composition and/or volume flowed back from the fracture-treated well;

— groundwater quality and unusual quality changes in the vicinity of the fracture-treated well;

— use of tracers in the fracture treatment and tracer detection logging or other logging techniques in the fracture-treated well and/or nearby wells after the job to determine fracture location indications; and

— post-treatment gas detection logs of the fracture-treated well and/or of nearby wells to investigate gas saturations behind casing and detect apparent change in saturation, if any.

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6.6 Well Remediation

6.6.1 General

A well identified as having compromised mechanical integrity shall be evaluated and responsive action implemented within a timeframe and by method(s) determined by the operator and corresponding to the severity of the integrity risk.

NOTE Section 8 assists the operator in characterizing risk and building integrity plans to address integrity monitoring and treatment.

6.6.2 Evaluation and Responsive Action

The operator should review logs, such as casing inspection logs or mechanical integrity tests, prior to planning and conducting well remediation activities.

The operator should assess the risk associated with working on a well at various reservoir pressures when planning remediation work.

If a well is to be kept out of active service for a length of time (as determined by the operator) before remediation occurs, but could otherwise act as a conduit for communication, the operator should continue to monitor the well.

Before placing a well back in service, the operator should reassess the well's integrity and address any newly identified integrity threats that may have developed during the remediation.

6.7 Well Closure (Plugging and Abandonment)

6.7.1 General

The operator shall design a well abandonment for long-term isolation of the storage zone in order to prevent fluid flow between the storage zone and any other penetrated zone and the surface.

NOTE See API E3 [18] for guidance on well abandonment practices and procedures.

6.7.2 Storage Zone Isolation

The operator shall use cement plugs (see 6.4.3) and/or mechanical plugs to isolate the storage zone from fluid migration. The use of hydrostatic pressure as a sole means of isolation shall not be acceptable.

Cement should meet quality standards in API 10A and ASTM C150/C150M or exceed the requirements set in these standards.

The operator should assess the long-term viability of the plug design to achieve and maintain the required isolation.

NOTE 1 The U.S. Bureau of Safety and Environmental Enforcement, Report RLS0116 [19] contains observations on cement plug viability.

A cement plug should be of a length that, whether by itself or in combination with a mechanical plug, achieves isolation of the storage zone.

NOTE 2 Several U.S. state regulatory agencies require a minimum cement plug length of 100 ft.

The well should be in a static condition prior to setting of a cement plug and during the curing process.

Volume-extending additives should not be used in cement plugs.

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The operator shall determine the location of groundwater and hydrocarbon bearing zones (in addition to the storage zone) penetrated by the well to be abandoned, and the condition of the well's casing and cement across those zones, to prevent communication between any of those zones during and after plugging of the well. Special provisions may be necessary to isolate formations behind uncemented casing.

The operator should evaluate the condition of the well to be abandoned for any issue that would limit access to the wellbore or hinder placing plugs across the storage zone and other critical zones in order to establish conditions for long-term plug sealing reliability across and against the storage zone.

The operator shall verify that the casing-borehole cement seals the storage interval in the well being abandoned in order to achieve annular isolation and prevent communication.

The operator shall verify the presence and location of a cement plug after the plug is set and has reached a sufficient compressive strength; the operator shall correct deviations which may threaten isolation objectives of the plug.

6.7.3 Abandoned Well Maintenance

The operator shall repair a failed plug; the operator shall repair a well with any leak indication that may suggest a lack of isolation of the storage reservoir.

In order to maintain the physical and site security of the abandoned well, the operator shall install a surface plug and cap. To make identification easier, the cap shall include the API number or other form of identification.

6.8 Environmental, Safety, and Health

6.8.1 Design and Construction Safeguards

Safeguards to the environment, safety, and health of workers and the public shall be incorporated into well design and well work activities.

NOTE Publications such as API 49 [20], API 51R, API 54 [21], and API 76 can be referenced to identify safeguards for application in storage well design and well work activities.

The operator shall take actions to protect surface water and groundwater resources in the design, drilling, and servicing of a well. The operator should conduct an environmental impact review prior to well drilling.

The operator shall monitor worksite conditions during well construction and well work activities in order to protect the environment and the safety and health of workers and the public.

6.8.2 Operation and Maintenance Safeguards

The operator should account for the long-term viability and functional integrity of the well in the well design and well work activities in order to promote the ability to maintain and operate the well consistent with environment regulations and to maintain worker and public safety throughout the life of the well.

The operator shall have an emergency response plan as described in Section 10.

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6.9 Testing and Commissioning

6.9.1 Testing Methods

A new well, or a well that has had its existing production casing modified from its previous condition during workover activities, shall be tested to demonstrate mechanical integrity and suitability for the designed operating conditions prior to commissioning by one of the following tests.

a) For new well construction, the production casing shall be tested prior to drilling out the shoe, taking into account the cement design factors so that this test does not compromise the cement integrity.

b) For existing production casing, the production casing shall be tested after setting a retrievable plug as close as practical to the top of the storage formation.

NOTE A commonly used test parameter is an initial test pressure of 1.1 times the maximum allowable operating pressure, with test duration of at least 30 minutes and a pressure drop not exceeding 10% of the initial test pressure. Applicable regulations may stipulate other parameters.

c) For a well completed with tubing and packer, the tubing-casing annulus shall be tested.

The operator shall design a test so the maximum pressure on the packer seat and the pressure at any point in the wellbore during the test does not compromise the mechanical integrity of the well.

6.9.2 Casing Inspection Logging

The operator should perform baseline casing inspection logging on new production casing. If an existing well is converted to be a storage well, the operator should perform a baseline casing inspection log on the production casing of the converted well.

6.10 Monitoring of Construction Activities

6.10.1 General

Gas storage development and replacement activities should be monitored and evaluated in a manner that verifies mechanical integrity in the design and construction of wells.

6.10.2 Procedures and Documentation

The operator should monitor and verify that construction procedures, as required in 11.2, are followed and documentation for project design, material and equipment acquisition, well construction, and commissioning are maintained, as described in 6.11.

6.10.3 Work Supervision

Well drilling, servicing, testing, and commissioning activities should be supervised at the job site by personnel who are aware of, trained in, and experienced in the company procedures, regulatory and safety requirements, and geological and engineering aspects related to the work being performed.

The operator should document that on-site supervisory personnel have the knowledge, skills, and abilities for the work to be performed under their supervision.

The operator should document that contractor equipment is suitable and personnel are capable for the work being performed and aware of the operator's procedures related to such work. Requirements related to contractor personnel are covered in 11.12.

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6.10.4 Resolution of Issues

The operator should monitor and address issues or problems encountered during drilling, completion, and stimulation of a well. If the resolution of encountered issues or problems causes the operator to deviate from the original design or to alter the procedures for a well, the operator shall document the changes and keep the document in the well records.

The operator shall resolve issues or problems in a manner that maintains functional integrity of the well and storage reservoir prior to commissioning the well for service.

The operator should determine if the resolutions to identified issues need to be incorporated into the design of future wells and treatments.

The operator should review the geologic or engineering data collected during well construction or remediation to determine if that information could impact or require changes in the reservoir characterization as outlined in 5.2 and 5.3.

6.11 Recordkeeping

6.11.1 Well Work Records

Records of well completion (as-built), well construction and well work activities shall be maintained for the life of the facility. These records shall include, as applicable and available, the items listed below as referenced in each subsection.

— *6.2 Wellhead Equipment and Valves*

  — Material and test records.

  — Design evaluations.

  — Emergency shutdown valve evaluation.

  — Inspection and repair records.

— *6.3 Well Casing*

  — Material and test records.

  — Design evaluations.

  — Setting depths of all strings of casing.

  — Connection design evaluation.

  — Connection torque verification.

— *6.4 Casing Cementing Practices*

  — Blends, additives, and volumes pumped.

  — Volume of cement circulated to surface.

  — pH of mix water and water temperature.

  — Pump and displacement rates and displacement times.

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- Preflush type and volume pumped.
- Type of float and centralization equipment and location in string.
- Theoretical and actual displacement volumes.
- Detail of remedial cementing work performed.
- Cement service company's field report and log of job.
- Logged cement placement and any evaluation of quality of seal.

— *6.5 Completion and Stimulation Considerations*

- Service company field reports and job logs.
- Location and description of stimulation treatments.
- Composition and volumes of any fluid used.
- Cementing reports (as detailed in 6.4).
- Type of equipment used and location in well.
- Cased hole correlation logs.
- Post-treatment monitoring data and analysis.

— *6.6 Well Remediation*

- Cementing reports (as detailed in 6.4).
- Type of equipment used and location in well.
- Well logs.
- Workover and recompletion reports.

— *6.7 Well Closure*

- Equipment removed from well.
- Cementing reports (as detailed in 6.4).
- Plugging records filed with local regulatory authorities.

— *6.9 Testing and Commissioning*

- Mechanical integrity test data.
- Pressure test data.
- Type and amount of fluid in annulus of tubing and packer completion.
- Casing inspection logs.

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— *6.10 Monitoring of Construction Activities*

  — Received equipment and material specifications.

  — Changes in well construction from original well design.

  — Rig and service company field tickets and job logs.

  — Daily drilling and servicing reports, geolograph records, and driller's log.

  — Mud records.

  — Wireline logs and mud logs.

NOTE Those records that relate to the current state of completion and functional integrity are most relevant.

6.11.2 Permitting, Procedures, Personnel, and Equipment Records

Records relating to permitting, procedures, personnel, and equipment shall be retained for a period that meets regulatory requirements, or where no regulatory requirements exist, intervals as determined by the operator. These records shall include, as applicable and available, the items listed below as referenced in each subsection.

— *6.8 Environmental, Health, and Safety*

  — On-site safety meeting records.

— *6.10 Monitoring of Construction Activities*

  — Supervisor qualifications.

  — Contractor personnel qualifications.

  — Equipment suitability records.

  — Contractor safety orientation.

7 Functional Integrity of the Natural Gas Storage Reservoir and Wells Established and Demonstrated Through Initial Attainment of Maximum Reservoir Pressure and Total Inventory

7.1 General

This section addresses the requirements for verifying functional integrity of the natural gas storage reservoir and wells during reservoir development and during commissioning until reaching the designed maximum reservoir pressure and/or total capacity. Section 9 addresses integrity demonstration, verification, and monitoring for existing storage reservoirs on an ongoing basis.

7.2 Testing and Commissioning

7.2.1 General

Facility integrity and baseline performance conditions should be established and documented in order to allow identification of anomalous conditions during commissioning and operation.

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7.2.2 Integrity Assurance

Mechanical integrity tests and/or mechanical condition evaluation shall be performed prior to project commissioning in order to verify that each well is capable of meeting the designed operating conditions. Requirements related to well mechanical integrity testing are covered in 6.9.

Wells identified for plugging or replugging should be scheduled for such work on a priority basis in accordance with the facility construction schedule and facility integrity plan (as described in 5.4.7), and in consultation with regulatory authorities, as applicable. Requirements related to well closure are covered in 6.7.

7.2.3 Baseline Conditions

Baseline pressure and volume conditions of the reservoir should be established and documented prior to commissioning, as discussed in 5.3.

Observation well baseline conditions such as wellbore pressure, pressure of monitored annuli, gas composition, and liquid level should be documented prior to commissioning.

Baseline quality of groundwater in the vicinity of the storage operation may be tested prior to commissioning or as specified by regulatory authorities.

7.3 Reservoir Integrity Monitoring

7.3.1 General

The material balance behavior of a storage reservoir shall be monitored relative to the original design and expected reservoir behavior established prior to commissioning and start-up. Unexpected conditions detected during monitoring shall be evaluated and corrected in order to avoid an incident or loss. Monitoring frequency should be based on factors such as reservoir and well fluid loss potential and flow potential.

7.3.2 Monitoring and Analysis Methods

Average reservoir pressure versus inventory shall be monitored and compared to expected conditions in order to allow for the discovery and correction of any unexpected conditions. Typically, a shut-in key indicator well(s) or an observation well(s) that represents the average shut-in reservoir pressure provides the most useful pressure-inventory relationship. In lieu of shut-in observation wells, the relationship may be based on a flowing well pressure. Liquid level should be taken into account when using observation wells. Semiannual field shut-in tests, usually occurring at the point of seasonally high and low inventories, should be conducted for inventory verification.

Strategically located observation wells in the vicinity of spill points, within an aquifer, and above the caprock in potential collector formations should be installed and monitored to detect the presence or movement of gas using methods which can include review of fluid level records, well pressures, geophysical logging, gas composition, or other tools and methods.

Offset hydrocarbon production or disposal operations should be monitored for unexplained flow or pressure changes. The monitoring should include operations in zones above and below the storage reservoir as well as laterally offset locations.

Subsurface correlation and gas identification logs such as gamma ray and neutron log suite may be obtained to confirm the location of gas being injected into the intended storage reservoir, as needed.

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7.4 Mechanical Integrity Monitoring

7.4.1 General

Wells and related facilities shall be monitored in order to allow for the discovery and correction of abnormal operating conditions.

7.4.2 Surface Monitoring Methods

Wellheads, well safety systems, well piping, and site locations should be inspected for operability, leaks, and mechanical or other faults.

Wellhead injection pressure and injection flow rate should be monitored for unexpected changes indicative of a mechanical fault.

Observation well pressures or fluid levels should be monitored for unexpected changes indicative of mechanical fault.

Well annulus pressures or vents should be monitored.

Plugged well site locations should be inspected for evidence of leakage or surface encroachments.

7.4.3 Subsurface Monitoring Methods

Subsurface pressure or temperature surveys to locate suspected flow anomalies may be performed, as needed. More sophisticated production logging tools such as spinner surveys or noise logs may be used to augment the investigation.

Subsurface mechanical condition surveys such as cement bond logs and casing inspection logs to identify suspected mechanical integrity issues may be conducted as needed.

Subsurface correlation and gas identification logs such as gamma ray and neutron log suite to locate suspected anomalous gas accumulations above or below the intended reservoir may be obtained as needed.

7.5 Recordkeeping

Records of natural gas storage testing and monitoring activities covered under this section shall be maintained for the life of the facility. The records shall include, as applicable and available:

a) reservoir and well mechanical integrity records that demonstrate functional integrity during commissioning, including monitoring data and analyses;

b) well testing records and records of well actions taken during commissioning; and

c) regulatory records for project commissioning including permit applications, permits, and all reports and correspondence with regulatory agencies.

8 Risk Management for Gas Storage Operations

8.1 General

This section addresses risk management for surface and subsurface facilities including the wells and reservoir but excludes pipelines and compressor stations. Risk is defined as the consequence of a realized threat multiplied by the likelihood of its occurrence.

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NOTE Bibliography Items [22] to [27] provide further references that various industries, including pipeline and storage operators, employ in the application of risk or asset management.

8.2 Risk Management

The operator shall develop, implement, and document a program to manage risk that includes data collection, identification of potential threats and hazards to the storage operation, risk analysis including estimation of the likelihood of occurrence of events related to each threat, the likelihood of occurrence and potential severity of the consequences of such events, and the preventive, mitigative, and monitoring processes to reduce the likelihood of occurrence and/or the likelihood and severity of consequences, and a periodic review and reassessment of the processes.

8.3 Data Collection and Integration

8.3.1 General

Identifying and collecting the information relevant to a storage field is part of risk management. Data review and integration can highlight conditions in need of attention or additional information collection, assist in threat and hazard identification and risk analysis, and contribute to the continual improvement process.

8.3.2 Data Sources

The operator shall use available information such as performance data collected through the field history, operations and maintenance (O&M) activities, geotechnical data such as well logs, engineering data, and completion reports to determine susceptibility to threat and hazard-related events and to assess threat and hazard interaction.

8.4 Threat and Hazard Identification and Analysis

8.4.1 General

A hazard is a situation or condition that has the potential to cause loss, damage, or harm to a storage well, well site, or reservoir and thus affect the functional integrity of the storage operation. A threat to storage functional integrity can be created by an encounter with or an activation of a hazard in the course of the storage operation. The operator may determine that some storage facilities are not susceptible to specific threats based on existing information, in which case the operator can provide justification and documentation for the exclusion of a specific threat. A lack of data or information should not be used as justification to exclude a specific threat.

8.4.2 Methodology

The operator shall evaluate the potential threats and hazards impacting storage wells and reservoirs. The operator should refer to the list of common threats and hazards in Table 1 and may supplement the list in Table 1 with other hazards or threats identified by site-specific assessments.

The operator should estimate risk from potential events that could occur related to potential threats and hazards to individual facilities, such as wells, and by region when considering the reservoir.

The operator should assess potential threat and/or hazard interaction, such as the relationship of the threat of casing damage during well drilling or service work that could exacerbate corrosion processes.

The operator should perform periodic evaluations of hazards, threats, and risks related to potential events in order to account for changes in perception of likelihood or consequence in event potential.

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Table 1—Potential Threats and Consequences

Category of Review	Threat or Hazard	Threat/Hazard Description	Potential Consequences
Wells	Well integrity (corrosion, material defects, erosion, equipment failure, annular flow)	Gas containment failure due to inadequately sealed storage well(s), e.g. casing corrosion, cement bond failure, material defect, valve failure, gasket failure, thread leaks, etc.	— Loss of stored gas inventory — Damage to well site facilities and equipment — Safety hazard to company personnel and the public — Loss of use of water sources and/or wells — Decrease or loss of field performance
	Design	Gas containment failure due to inadequately completed wells, sealed plugged well(s), failure of cement squeeze job perforations or stage tool, pressure rating of components, etc.	— Release of gas to the atmosphere — Damage to well site facilities and equipment — Safety hazard to company personnel and the public — Loss of use of water sources and/or wells — Loss of stored gas inventory — Decrease or loss of field performance
	Operation and maintenance activities	— Inadequate procedures — Failure to follow procedures — Inadequate training — Inexperienced personnel and/ or supervision	— Loss of stored gas inventory — Damage to well site facilities and equipment — Safety hazard to company personnel and the public — Loss of use of water sources and/or wells — Decrease or loss of field performance
	Well intervention	Gas containment failure due to loss of control of a storage well while drilling, reconditioning, stimulation, logging, working on downhole safety valves, etc.	— Damage to drilling rig or service rig — Loss of tools in wellbore — Hazard to operator and service company personnel on well site — Safety hazard to public — Decrease or loss of field performance — Loss of well

	Third-party damage (intentional/ unintentional damage)	Intentional/unintentional damage	— Accidental impact by moving objects (e.g. farm equipment, cars, trucks, etc.), vandalism, terrorism that could result in damage to facilities:
			  — loss of ancillary facilities
			  — well on/off status change
			  — impact to service reliability
			  — impact to neighboring public, storage gas loss

	Outside force—natural causes	Weather related and ground movement	— Heavy rains, floods, lightning, earth movements, groundwater table changes, subsidence, etc. that could result in: — damage to facilities/impact to service reliability

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Table 1—Potential Threats and Consequences (Continued)

Category of Review	Threat or Hazard	Threat/Hazard Description	Potential Consequences
Reservoir	Third-party damage (third-party well operations)	Third-party drilling, completion, and workover activities	— Drilling into, through, or adjacent to the storage reservoir could result in loss of containment — Production well stimulation damages to storage well — Poor cement bond that could result in inability to meet design performance requirements — Loss of stored gas inventory — Damage to third-party/public property and personnel
		Third-party production, injection, or disposal operations	— Decrease in field performance (both working gas cycling and deliverability) — Loss of stored gas inventory — Safety hazard if pressure rating of production facilities are not as high as storage pressure — Inability to meet design performance requirements — Damage to third-party/public property and personnel
	Geologic uncertainty	Uncertainty of extent of reservoir boundary	— Gas migration beyond control of storage wells — Behavior of field under storage operations different than under production that could result in storage gas loss — Inability to meet design performance requirements — Damage to third-party/public property and personnel
		Expansion, contraction, and migration of storage gas	— Expansion, contraction, and migration due to operations that could result in inability to meet design performance requirements and loss of stored gas inventory
		Failure of caprock	— Vertical gas migration, likely during testing phase, initial activation, or when initial pressure is exceeded that could result in gas migration into shallower zones including water sources — Loss of stored gas inventory — For existing field a potential abandonment or requirement of re-cycling facilities
	Reservoir fluid compatibility issues	Contamination of storage reservoir by foreign fluids	— Wellbore damage caused by drilling and completion fluids, water/chemical floods, H_2S generating bacteria, stored gas quality, etc. — Internal corrosion that could result in a degradation to field performance (both working gas cycling and deliverability) and well and/or pipeline repairs/failures

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Table 1—Potential Threats and Consequences (Continued)

Category of Review	Threat or Hazard	Threat/Hazard Description	Potential Consequences
Surface	Third-party damage (surface encroachment)	Surface encroachments	— Buildings/roadways/structures construction, cathodic protection current from pipelines, power line current and overhead wires, expansion of park lands, mining, flood control dams, etc. that could result in: — inability to access, operate or maintain facilities — facility abandonment — reduced ability to site additional wells and facilities due to setback restrictions
	Third-party damage (intentional/ unintentional damage)	Intentional/unintentional damage	— Accidental impact by moving objects (e.g. farm equipment, cars, trucks, etc.), vandalism, terrorism that could result in damage to facilities: — loss of ancillary facilities — well on/off status change — impact to service reliability — impact to neighboring public, storage gas loss
	Outside force—natural causes	Weather related and ground movement	— Heavy rains, floods, lightning, earth movements, groundwater table changes, subsidence, etc. that could result in: — damage to facilities/impact to service reliability

8.5 Risk Assessment

8.5.1 General

Risk assessment uses tools and techniques that evaluate and prioritize risks to direct risk management activities toward promoting functional integrity of the storage operation.

8.5.2 Methodology

The operator shall assess risk related to the storage operation using a consistent process.

The operator should determine the risk assessment method applicable for the facilities. A risk assessment method should include the following characteristics in the risk assessment protocol:

a) identification of potential threats and hazards to a storage facility;

b) evaluation of likelihood of events and consequences related to the events;

c) determination of risk ranking to develop preventive and mitigating measures to monitor and/or reduce risk;

d) documentation of risk evaluation and decision basis for preventive and mitigative (P&M) measures;

e) provision for data feedback and validation; and

f) regular, periodic risk assessment reviews to update information and evaluate risk management effectiveness.

The operator shall review the results of the risk assessment to determine whether the risk assessment, resulting prioritization, or ranking represents its facilities and characterizes the risks. Review may be performed by personnel familiar with storage operations, risk management, and methods of analyzing risk and results.

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8.6 Preventive and Mitigative Measures

8.6.1 General

P&M measures are actions conducted by the operator to reduce the risks to the storage facilities by reducing the likelihood (preventive) or reducing the consequence (mitigative) of events related to the threats identified in 8.4. The P&M measures include routine condition monitoring activities since the acquisition and analysis of data provides information upon which additional measures can be implemented. Table 2 presents a list of programs, methods, or tools commonly employed by operators to monitor and manage risks. The table further provides a reference of those sections in this RP that address risks identified by the operator.

Table 2—Preventive and Mitigative Programs

Category of Review	Threat or Hazard	Preventive/Mitigative Treatment or Monitoring Programs	Reference Location(s) of Program in API 1171
Wells	Well integrity (corrosion, material defects, erosion, equipment failure, annular flow)	Casing condition and inspection program	9.3
		Monitoring pressure, rate and inventory	9.6
		Cement analysis and evaluation	5.3; 6.4
		Internal corrosion monitoring	9.3
		Plugged and abandoned well review and surveillance	5.3; 6.7; 9.3
		Monitor annular pressures, rates, or temperatures	9.3
		Subsurface and surface shut-off valves	9.3; 6.2
		Monitor cathodic protection as applicable.	9.3
		Operate, maintain, and inspect valves and other components	9.3
	Design	Collect and evaluate plugged and abandoned well records and rework or plug	5.3; 7.2; 6.7; 9.3
		Develop design standards for new wells	Section 6 (all except 6.5, 6.6, and 6.7)
		Evaluate current completion of existing wells for functional integrity and determine if remediation monitoring is required	5.3; 6.2, 6.3, 6.4; 9.2, 9.3
	Operations and maintenance activities	Procedures	11.2
		Training of personnel and contractors and establishment of procedures	11.12; 6.10
	Well intervention	Implement training and safety programs for company and contractor personnel	11.2; 10.6 (for emergency response training)
		Develop detailed drilling and well servicing procedures	11.5

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Table 2—Preventive and Mitigative Programs (Continued)

Category of Review	Threat or Hazard	Preventive/Mitigative Treatment or Monitoring Programs	Reference Location(s) of Program in API 1171
Reservoir	Third-party damage (third-party well operations)	Bilateral agreements or statutory requirements for production wells to incorporate additional design features to isolate the storage horizon during drilling, completion, stimulation, and production. Examples include a separate string of cemented casing across the storage horizon and maintaining an adequate vertical and lateral buffer from the storage reservoir.	9.3, 9.4
		Agreements with third-party production operations to have access and observation during the drilling, completion, and production phases	9.3, 9.4
		Monitor drilling and mining permits and activity	9.4
		Promote development of rules and regulations for the protection of storage from third-party oil and gas development	11.10 (policy and public awareness)
		Surface and subsurface setback requirements from storage wells and well sites for both vertical and lateral buffer zone	9.3, 9.4
		Gas sampling analysis of storage wells and production wells and collection of production data to review for communication by storage operations	9.3, 9.4
		Acquire third-party production wells and mineral rights	5.2; 5.3; 9.4
		Pursue legal options (condemnation, enjoin production, etc.)	5.2, 5.3; 9.4
	Geologic uncertainty	Collect and review existing regional geological studies and data	5.2; 9.4
		Collect geological, geophysical, and reservoir data on existing wells in/adjacent to the storage field	5.2; 5.3; 9.4
		Acquire new data (e.g. electric logs, new wells, core, seismic, well testing, tracer gas studies, etc.)	5.4; 9.4
		Establish buffer zone, (vertical and horizontal) with governing agency and update as necessary	5.2; 5.3; 9.4.
		Conduct semiannual tests for inventory verification	9.5
		Acquire property and mineral rights	5.2; 5.3; 9.4
		Establish observation wells based on evaluation of need	5.4; 9.4
		Inspect plugged and abandoned wells, review records	9.3
	Reservoir fluid compatibility issues	Conduct fluid compatibility studies on samples of the reservoir rock and/or review of literature	5.3; 9.3
		Conduct internal corrosion studies and evaluate mitigation programs as needed	9.3
		Monitor composition and quality of gas	9.4, 9.5

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Table 2—Preventive and Mitigative Programs (Continued)

Category of Review	Threat or Hazard	Preventive/Mitigative Treatment or Monitoring Programs	Reference Location(s) of Program in API 1171
Surface	Third-party damage (surface encroachment)	Ensure surface operating rights agreements (e.g. leases, easements, etc.) clearly specify storage operator's rights for ingress, egress, and mutual setback distances from wells/structures, etc.	9.3, 9.4; 10.3
		Work with landowners, local planning/zoning commissions, and others on the surface operating requirements around storage wells	11.10
		Use of existing public awareness activities required for pipelines	11.10
		Monitor use of the surface and subsurface around wells and enforce setback rights when encroachments threaten the well	9.2, 9.3; 10.3
	Third-party damage (intentional/unintentional damage)	Install protection equipment (e.g. fences, alarms, etc.) for site security and safety	6.2; 10.2
		Include storage facilities into the corporate security plans	10.2
		Develop storage well blowout contingency plan	10.6
		Liaison with local, state, and federal law enforcement agencies	10.6
		811 Call-Before-You-Dig programs (damage prevention program)	11.10
	Outside force—natural causes	Perform routine patrols and surveillance, and event-specific surveillance activities	10.5
		Develop design specifications (e.g. barriers to deflect flood debris) for areas prone to flooding, earth movements, river/stream bed movement, and other natural causes	10.2, 10.3
		Develop site-specific plans for known problems such as areas prone to flooding, earth movements, river/stream bed movement, and other natural causes	5.4; 9.2; 10.6
		Monitor areas prone to flooding, earth movements, river/stream bed movement, and other natural causes for impacts on nearby well sites	10.5, 10.6
		Plug and abandon a well and drill replacement in more stable location	6.7, 6.10
		Remote control capabilities	6.2

8.6.2 Methodology

The operator shall develop P&M measures to manage risks.

The operator should review the P&M measures listed in Table 2 to determine those measures that manage risks based on site-specific conditions. Not all risks need a P&M measure if the level of risk is fully acceptable or if it is not necessary to reduce risk by further efforts.

The operator should employ the effective P&M measures and train their personnel on the procedures related to the P&M measures (see Section 11). The operator can apply these P&M measures to individual wells, individual reservoirs or fields, and/or groups of wells or fields.

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8.7 Periodic Review and Reassessment

8.7.1 General

The operator shall assess the effectiveness of risk monitoring and risk management programs and maintain a continual review and improvement cycle in risk management activities to provide functional integrity of the storage operation. The interval of review and reassessment should be short enough to identify operational and monitoring trends and measure the effectiveness of P&M measures, but long enough that the data and information that can be brought into the analysis are meaningful.

8.7.2 Frequency

The operator shall define a review frequency for the risk assessment and perform a review and update of the risk assessment in accordance with the defined frequency.

8.7.3 New Threats and Hazards

If during the course of operations new threats or hazards are identified, or the impact of threats or hazards changes markedly, the operator shall assess the risk associated with new conditions and evaluate and prioritize risk management options in accordance with the risk assessment.

8.7.4 Procedures

The operator should develop procedures that define the data or information to be reviewed, and methods of data trending or normalization in the context of the risk assessment, by analyzing such factors as integrity performance and the number and types of issues that are occurring, as well as other conditions that might trigger an evaluation at a shorter frequency (e.g. new encroachments, third-party drilling).

8.7.5 Evaluation Team

The operator should use a multi-disciplinary team for the review and reassessments.

8.7.6 Performance Measures

The operator should determine specific performance measures to monitor and review in order to determine if risk management actions need revisions or additional P&M measures.

8.8 Recordkeeping

The operator shall develop a risk management records retention schedule and management plan. The operator should define the records retention period. Risk management documentation can include data used during the risk assessment, P&M measures employed, and the periodic evaluation of performance metrics.

9 Integrity Demonstration, Verification, and Monitoring Practices

9.1 General

This section provides a methodology and requirements for storage reservoir and well integrity demonstration, verification, and monitoring.

9.2 Overview

9.2.1 Integrity Maintenance

The operator shall maintain functional integrity of storage wells and reservoirs. Storage wells and reservoirs can have different characteristics resulting in unique requirements in approaching integrity demonstration, verification, and monitoring.

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NOTE Operating and maintenance practices, repair or replacement of defective wellhead, valve, casing, or wellbore components, and/or temporary mitigative actions such as reducing operating pressure are examples of methods used as necessary to maintain functional integrity.

9.2.2 Risk-based Evaluation

Risk assessments shall be used as a basis for developing the integrity demonstration, verification, and monitoring tasks and evaluating their frequency requirements (see Section 8). Following the risk assessment, the operator should develop and maintain a program and procedures to address storage reservoir and well integrity monitoring practices for each storage facility, multiple facilities, and/or system-wide. The operator's approach should address the need for reevaluation of risk-based conclusions and the monitoring task frequency.

9.3 Well Integrity Demonstration, Verification, and Monitoring

9.3.1 Well Integrity Evaluation

The operator shall evaluate the mechanical integrity of each active well, including each third-party well, that penetrates the storage reservoir and buffer zone or areas influenced by storage operations.

Well integrity evaluation methods typically used by operators include but are not limited to review of design, completion, and well work records, wellhead and downhole inspection, well pressure monitoring and testing, and gas sampling.

The operator shall request well integrity evaluation data from third-party well owner/operators following the frequency established using conclusions from the risk assessment.

Active well mechanical integrity evaluations shall include initial and subsequent evaluations as determined using the risk assessment and the information derived from the initial evaluation.

9.3.2 Well Integrity Monitoring

The operator shall monitor for presence of annular gas by measuring and recording annular pressure and/or annular gas flow. The operator shall evaluate each annular gas occurrence that exceeds operator- or regulatory-defined threshold levels determined from well integrity evaluation and from risk assessment. The operator should test wellhead seals when annulus pressure is detected and where injectable packing and/or test ports are present.

The operator shall visually inspect each wellhead assembly at least annually for leaks. The operator shall test the operation of the master valve and wellhead pipeline isolation valve at least annually for proper function and ability to isolate the well. The valves shall be maintained, repaired, or replaced in accordance with the operator's valve maintenance program for isolation valves.

Surface and subsurface safety valve systems, where installed, shall be function-tested at least annually. The tests shall be conducted in accordance with manufacturer's recommendations and the operator's procedures.

A closed storage well safety valve system shall be manually reopened at the site of the valve after an inspection and not opened from a remote location.

The operator should monitor for tubular corrosion and evaluate corrosion impact on well integrity and operating pressure using risk assessment. Corrosion monitoring and evaluation should address the following:

— evaluation of tubular integrity and identification of defects caused by corrosion or other chemical or mechanical damage;

— corrosion potential of wellbore produced fluids and solids, including the impact of operating pressure on the corrosion potential of wellbore fluids and analysis of partial pressures;

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— annular and packer fluid corrosion potential; and

— corrosion potential of current flows associated with cathodic protection systems.

The operator should obtain a baseline gas detection log on each new well for use in detecting changes in gas indications behind casing throughout the wellbore over the life of the well.

The operator should identify the recorded location of plugged wells that penetrate the storage reservoir, within the buffer zone, or areas influenced by storage operations and inspect each well site for evidence of gas or other fluid flows to surface. Frequency of inspection should include an initial inspection and subsequent inspections as determined using Section 8. The operator should review plugging records to augment the plugged well site inspections.

The operator should inspect adjacent active and plugged wells during or following a stimulation or hydraulic fracturing treatment to verify integrity maintenance when a well located within the reservoir area and buffer zone is being treated at pressures exceeding maximum storage reservoir pressure.

The operator should monitor active and plugged well sites for encroachment activities that may impact well integrity.

The operator should monitor shut-in well pressure trends for indications of well integrity or loss thereof.

The operator may obtain compositional analysis of water samples taken from the storage reservoir or other formations for potential comparison to water that may accumulate within the wellbore during storage operations to identify possible well integrity problems.

9.4 Reservoir Integrity

9.4.1 Geological Characterization

The operator should review and update reservoir geological characterizations and mapping as new data become available or if there is evidence of changes in the location of gas or in the level of pressure in the reservoir to identify the limits of the gas and any spill points (see 5.2 for additional information on geological reservoir characterization).

9.4.2 Buffer Zone

The operator should review both the lateral and vertical components of the buffer zone as additional geologic or operational data become available, to determine if the boundaries continue to protect the integrity of the reservoir.

9.4.3 Third-party Activity

The operator should monitor for third-party activity that could compromise the integrity of the storage reservoir. Such activities can include drilling, completion, plugging and abandonment, production, mining, or other site-specific activities. The operator should determine P&M measures and contact the third-party or regulatory agencies to foster implementation of those P&M measures.

New third-party wells located within the lateral and vertical buffer zone should be drilled and completed in a manner to isolate the storage reservoir as recommended by the storage operator.

Third-party wells located within the lateral and vertical buffer zone being plugged and abandoned by the third party should be plugged in a manner to isolate the storage reservoir and protect its integrity.

NOTE A written agreement stating the storage operator's requirements for protecting the storage reservoir is sometimes negotiated with third parties actively drilling or producing within the reservoir area and buffer zone.

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9.4.4 Observation Wells

The operator should use observation wells around, above, or below the reservoir to monitor pathways of potential communication and/or migration.

NOTE Aquifer storage reservoirs use observation wells to monitor potential gas migration at locations such as reservoir spill points and potential collection points in porous formations above the caprock.

9.4.5 Gas Composition

The operator should obtain compositional analysis of gas samples taken from available shallower zones or casing annuli for comparison to gas analysis from the storage reservoir to identify potential gas leakage or gas migration pathways.

9.5 Gas Inventory Assessment

9.5.1 Total Inventory

The operator should include in the total inventory for the reservoir the estimated remaining native gas at time of conversion, the injected base gas, and the working gas on the date of the test when performing inventory verification analyses.

9.5.2 Data Quality

The operator should investigate, document, and take steps to mitigate sources of uncertainty in data collected for inventory assessment purposes and the analysis of that data, including but not limited to calculations, gas measurement procedures, and shut-in pressure stabilization time.

9.5.3 Hydrocarbon Reservoir Methodology

For a storage reservoir converted from a depleted hydrocarbon reservoir, the operator should use methods of inventory assessment based on reservoir operating characteristics, including but not limited to:

— conducting semiannual low and high inventory (generally in the spring and fall) storage pressure surveys (Section 8, Table 2) to obtain a representative reservoir pressure at low and high inventories;

— performing material balance studies using the reservoir pressure and inventory data collected during the semiannual surveys;

— monitoring shut-in well pressure trends for indication of gas migration; and

— using key indicator wells to monitor the pressure relative to inventory.

9.5.4 Aquifer Reservoir Methodology

For an aquifer storage reservoir and/or converted depleted hydrocarbon reservoir with a strong water drive, the operator should use inventory assessment methods based on reservoir operating characteristics, including but not limited to:

— using key wells to monitor the pressure relative to inventory;

— calculating pound-days operated above and below aquifer pressure;

— monitoring fluid levels and pressures in observation wells above and surrounding the field; and,

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— performing gas pore volume calculations.

NOTE Aquifer storage reservoirs operate at pressures above and below aquifer pressure, resulting in water efflux and influx, and changing gas reservoir size. Therefore, semiannual surveys are often not effective in inventory assessment. In addition, extended shut-in periods, whether at high or low inventory levels, result in changes in the reservoir volume that could be detrimental to the reservoir's operation.

9.5.5 Additional Actions

The operator should account for measured and unmeasured storage gas inventory changes such as injections, withdrawals, fuel, operations, losses, or other uses.

The operator should calibrate pressure gauges and document the calibrations according to operator's procedures.

The operator should account for wellbore liquid levels, where wellbore liquid levels are suspected to be present, when analyzing wellhead and/or bottomhole pressure data for reservoir integrity with necessary corrections made for elevation and fluid gradients.

The operator should create and regularly update a pressure-inventory relationship for comparison to the design relationship as a means of monitoring reservoir integrity.

NOTE The pressures used in the analysis can be from key indicator wells, shut-in of key active wells, and/or periodic pressure surveys of the entire field.

The operator should monitor the injected and withdrawn gas composition as needed to allow updates to the characterization of the gas in place.

9.6 Flow and Pressure Monitoring

9.6.1 General

The operator should monitor the injection and withdrawal flow rates and pressures at each storage reservoir to assist in evaluating facility integrity.

NOTE Injection and/or withdrawal rates and corresponding field pipeline pressure variations from expected levels are useful to alert the operator of potential reservoir and/or well integrity issues.

9.6.2 Deviations

Well pressure and/or flows should be monitored for deviations from expectations to alert operators of potential wellbore integrity issues. A risk assessment can be used to determine the frequency and type of monitoring required.

9.6.3 Flow Erosion

The operator should monitor and assess flow conditions and limit the potential for erosion due to flow velocity. The operator should be aware of differences in erosion potential of flow velocity for dry gas flow and for wet or particle-laden flow. The operator should monitor casing and wellhead component wall thickness at facilities where the conditions are suitable for erosion to occur. The frequency of wall thickness monitoring should be evaluated using risk assessment.

9.7 Integrity Nonconformance and Response

The operator should implement and maintain a program that provides a method of addressing and documenting nonconformance with regard to design criteria for well and reservoir integrity. Abnormal operating conditions encountered or anomalies discovered and actions taken to address each occurrence should be documented.

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9.8 Recordkeeping

9.8.1 Documentation

Inspections, tests, patrols, or analyses shall be documented according to the operator's procedures.

9.8.2 Retention

The operator shall maintain records of storage inventory assessments for the life of the facility.

10 Site Security and Safety, Site Inspections, and Emergency Preparedness and Response

10.1 General

This section addresses requirements for assessment and monitoring of site security and emergency preparedness to ensure the protection of operating personnel, the public, and underground natural gas storage facilities. It is the intent of this section to enable operating personnel to recognize and respond to abnormal operating conditions to protect life and property. These requirements are site specific and vary based on local conditions such as population density, terrain, land use, and environment of areas adjacent to the facility.

10.2 Site Security and Safety

10.2.1 General

In order to maintain site security and safety, the operator should maintain a process to limit access to storage wells during drilling, workover, operation, and abandonment activities; this requirement may be addressed through the use of a site access control plan. Security measures should be suited to the well flow potential, location, population density, natural forces, vandalism, terrain, and environment of areas adjacent to the facility.

10.2.2 Site Security and Safety

The operator should implement and maintain site security and safety measures. The operator should evaluate local and site-specific conditions in developing the security measures and may include requirements for:

— security check points;

— barricades such as bollards, jersey barriers, or concrete impediments;

— industrial-type steel mesh fencing;

— locking gates;

— security lighting;

— security cameras;

— alarm systems;

— windsocks;

— wellhead enclosures;

— valve handles removed, or valves secured; and,

— other means of preventing unauthorized entry or operation of storage facilities.

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The operator may employ additional measures to enhance site security and safety based on an analysis of site-specific factors. The operator may develop site-specific security and safety procedures for employees, contractors, and authorized visitors and establish and maintain training on the site-specific procedures.

10.2.3 Flammables

Sources of ignition and flammable-type equipment and materials should be located in a manner to provide for the ongoing safety at the wellhead or well site. The operator should evaluate the site-specific conditions of potential flow rates, pressures, and weather conditions when determining a safe distance from the wellhead for each source of ignition and flammable-type equipment and materials.

10.3 Ingress and Egress

10.3.1 Roads

Lease or well roads should be maintained in a condition that permits personnel and equipment access to the well.

10.3.2 Fences and Enclosures

Ingress or egress of the site may be controlled by fences or enclosures. When used at well locations, fences or enclosures shall comply with applicable fire codes and regulations.

10.4 Signage

10.4.1 Minimum Signage Information

Permanent weatherproof signage shall be installed at each well site for identification purposes. Signage should contain the following information, at a minimum:

— storage facility name, well name, and/or identification number;

— operator name; and,

— operator's 24-hour emergency contact number.

10.4.2 Additional Information

The operator can add other information or signage to enhance site security and safety; such additional information could include applicable location information or warnings for areas containing potentially hazardous, flammable, or noxious vapors.

10.5 Site Inspections

10.5.1 General

Site inspections for review of safety and security assurance should be performed to verify that requirements of this section are met and maintained.

NOTE Site inspections for safety and security can coincide with site inspection to check the well area for mechanical integrity purposes as detailed in 9.3.

10.5.2 Procedures

The operator should develop and implement procedures to ensure an effective inspection. Procedures should include:

— purpose of the inspection;

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— identity of the trained person conducting the inspection;

— frequency of inspection;

— items to be inspected in the form of a list that can be checked off as completed and become part of the inspection record;

— reassessment of hazards and potential threats; and,

— documentation, reporting, and recordkeeping requirements.

10.5.3 Risk Mitigation

The operator should plan and implement site security risk mitigation steps as appropriate.

10.6 Emergency Preparedness/Emergency Response

10.6.1 Emergency Preparedness/Emergency Response Plan

For site security and safety, the operator shall develop and implement a structured emergency preparedness/ response plan in order to address accidental releases, equipment failures, natural disasters, and third-party emergencies. The operator should integrate natural gas storage emergency procedures with regulatory required procedures covering pipeline facilities where possible rather than creating storage-specific documents. The plan should include:

— company name;

— facility name;

— facility location (or 9-1-1 address, if available);

— personnel roles and responsibilities;

— internal and external communication protocol;

— emergency contact information including area codes;

— procedures for notification;

— procedures for response to leaks, fires, medical emergencies, explosions, and natural emergencies;

— procedures for response to release of hazardous materials;

— hazardous materials inventory; and,

— special considerations for accidental hydrocarbon release and well blowout.

NOTE Civil responders use the Incident Command System.

10.6.2 Training

Storage operations and applicable staff shall receive training in the use of the emergency preparedness/response plan. The training can include mock drills and participation in table-top exercises at regular intervals. The table-top exercises or mock drills can include civil emergency responders to enhance understanding and successful incident response.

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10.6.3 Blowout Contingency Plan

The operator shall have a blowout contingency plan in place.

A blowout contingency plan is company specific and should identify the procedures, equipment, and personnel needed to avoid or respond to a loss of well control situation.

NOTE The operator can consult with well control experts in developing a blowout contingency plan.

10.7 Cyber Security

To the extent that transmitted well data or remote flow control activities are security issues, the operator may employ cyber security measures in order to provide site security and safety.

11 Procedures and Training

11.1 General

This section addresses requirements for the development, implementation, and maintenance of programs, plans, and procedures intended to safely and effectively guide the operator in design, construction, operation, and maintenance of underground natural gas storage facilities. Associated requirements are set forth regarding training of operator and contractor personnel to comply with established programs and procedures. Documentation and record retention to demonstrate compliance with or deviations from the programs, plans, and procedures are also addressed. The programs, plans, and procedures required in this section specifically cover gas storage wells and reservoirs; however, related pipeline and other regulated parts of the storage facility require the operator to have in place similar programs and procedures. Many publications and standards cover engineering requirements and recommended practices that impact the safe and reliable design, operation, and maintenance of underground natural gas storage reservoirs and related facilities. The operator is encouraged to review available resources including other API standards and ASME standards as well as other resources for possible guidance in development of their specific procedures.

11.2 Procedures

11.2.1 Construction, Operation, and Maintenance Procedures

The operator shall develop and follow procedures for the construction, operation, and maintenance of natural gas storage wells and reservoirs to establish and maintain functional integrity. When practicable, the operator's procedures should incorporate applicable industry recommended practices that promote personal and process safety, resource conservation, environmental stewardship, mechanical integrity, and reliable performance.

Procedures shall be in place prior to the development of a new storage facility. The procedures should address the minimum requirements for construction including drilling and other well entry work, reservoir integrity monitoring and management, O&M, emergency response, control room communications and responses, personnel safety, safety management systems, and site-specific procedures determined to be necessary by the operator.

Programs should integrate storage well and reservoir elements so that procedures and programs work together to promote the functional integrity of the storage facility.

The operator should integrate natural gas storage procedures with regulatory-required procedures covering pipeline facilities where possible rather than creating storage-specific documents. The operator might already have in place procedures for operation and maintenance, emergency response, integrity management, control room communications, qualification of personnel, management of change (MOC), and other procedures covering pipeline facilities. Specific operations related to natural gas storage wells and reservoirs requiring procedures include but are not limited to drilling, well workover, and reservoir integrity monitoring and management programs.

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A procedure should be written in clear language with enough detail to allow a person with appropriate training and experience to follow the procedure and achieve the desired objectives on a consistent basis.

Current procedures shall be available and readily accessible to operations, maintenance, and storage personnel. Procedures may be kept in paper or electronic format.

11.2.2 Review of Procedure Content

Procedures should be reviewed at a minimum frequency mandated by regulatory requirements, or if no requirements exist, as determined by the operator to ensure procedures are representative of current operations and technology. Procedures should be modified to account for changes in operating conditions, advancements in technology, regulatory changes, abnormal operating conditions, or as experience dictates. Procedure reviews should be documented and deficiencies or other changes noted in the review records. Implementation of changes should be documented as per 11.11.

11.2.3 Review of Procedure Adequacy

The operator should review the work being done by storage personnel to determine the adequacy and effectiveness of the procedures used in normal operation and maintenance of storage facilities. Reviews should be conducted periodically at a frequency determined in accordance with risk assessment practices recommended in Section 8. The operator should identify and document deficiencies, nonconformance, or deviations from established procedures and correct deficiencies or modify procedures as appropriate.

11.2.4 Record Retention

The operator should retain records necessary to properly administer the procedures and establish retention requirements for specific records.

11.3 Operations and Maintenance

11.3.1 General

The operator shall develop and implement O&M procedures covering storage wells and reservoirs prior to the commissioning operations set forth in Section 7.

11.3.2 Scope of Procedures

Procedures should outline and define routine inspection, testing, and monitoring activities (see Section 9), P&M measures for risk reduction (see 8.6), recognition of abnormal operating conditions, and the associated schedules and recordkeeping requirements. The procedures should address indications and/or circumstances identified during routine activities that may require supplemental activities or additional maintenance.

The operator should adapt and enhance general procedures when additional integrity monitoring activities are required to address special site-specific hazards or threats.

The operator should establish general procedures for well isolation necessary to perform maintenance functions, including options of venting, flaring, blow down, or other isolation procedures, as well as an assessment of the characteristics and volume of fluids in the context of safety and environmental protection.

The operator should develop procedures to identify abnormal operating conditions, respond to those conditions, and document those events. The procedures should require a periodic review of documented abnormal operating conditions for the purpose of establishing trends or lessons learned and modifying existing procedures to prevent recurrence.

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11.4 Emergency Plans

11.4.1 General

Emergency preparedness/response and blowout contingency plans referenced in 10.6 are required.

11.4.2 Plan Effectiveness

The operator shall establish a program to determine operator familiarity with emergency plans and procedures and periodic testing of the effectiveness of the plan in accordance with 10.6.

11.5 Well Work

11.5.1 General

The operator should establish a program to manage drilling, completion, servicing, and workover activities. This program should incorporate in a work plan the operator-established practices and procedures that are founded on industry recommended practices related to the drilling, completion, servicing, or workover operation to be performed. The work plan at a specific well should identify site-specific requirements, and the plan should account for hazards and conditions expected to be encountered in the well.

11.5.2 Scope of Procedures

The operator's established procedures should define minimum safety requirements for surface equipment, pressure control equipment, downhole operations, MOC processes, elements of process safety management, and other requirements as specified by regulations and the operator.

Drilling, completion, servicing, and workover plans should be reviewed with rig crews and other contractors as applicable prior to performing the work.

The operator's well-specific work plan should identify the pressure rating of blowout preventers and ancillary pressure control equipment. The pressure rating should be greater than the maximum anticipated surface pressure, and the plan should include requirements for verification and documentation that blowout preventers are in good working condition and have been tested after installation.

NOTE API 53 [28] and API 54 provide guidance related to blowout prevention equipment for drilling and well servicing operations.

The operator should require personnel whose duties include operation of well control equipment used in the drilling, completion, servicing, or workover operations to demonstrate knowledge, skill, and ability to operate the equipment (see 11.12).

The operator should require a person who is qualified in well control, or knowledgeable, skilled, and capable through experience to perform well control duties, to be on site at the well during active drilling, completion, servicing, and workover operations.

11.5.3 MOC During Drilling, Completion, and Servicing

The operator should define a MOC process to promote safety when unanticipated conditions are encountered in well drilling, completion, servicing, and workover operations. The process should include requirements for approval or authority for deviating from the procedures, making decisions, waiving existing procedures, and documentation of the change.

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11.6 Other Well Entry and Well Operation Procedures

11.6.1 General

The operator should establish a work plan when performing wireline, slickline, and logging operations, well testing, and other well operations requiring well entry. The plan should incorporate operator-established practices and procedures that are founded on industry recommended practices and applicable to the specific work to be performed. The work plan at a specific well should identify site-specific requirements and the plan should account for hazards and conditions expected to be encountered in the well.

11.6.2 Scope of Procedures

The operator should define operating conditions and activities where pressure control equipment is required.

The work plan should require that pressure control equipment be rated for the maximum anticipated surface pressure to be encountered during the operation.

The operator should verify that equipment used for pressure control is in good operating condition and suitable for the intended operation.

NOTE API 54 provides guidance related to pressure control equipment used in drilling and well servicing operations.

The operator should review the wellbore entry plan with the contractor prior to beginning the work.

The operator should confirm prior to wireline, slickline, and logging operations that the contractor is provided with:

a) well configuration and completion details;

b) characterization of the stored hydrocarbons and the presence of H_2S or other hazardous or corrosive agents;

c) anticipated wellbore and storage zone pressures and temperatures;

d) anticipated presence of water, fluids, deposits, or scale and restrictions in the wellbore;

e) safety requirements as outlined in 11.9; and,

f) reporting requirements.

11.7 Interaction with Control Room

11.7.1 General

Storage personnel shall be responsible for preparing and communicating guidelines for maintaining reservoir and well functional integrity.

11.7.2 Scope of Procedures

The operator should establish procedures for interaction and communication with a control room, including authority for initiating flow, operating, and shutting in natural gas storage facilities as required in order to maintain reservoir and well integrity during normal, abnormal, and emergency conditions.

11.8 Integrity and Risk Management

11.8.1 General

The operator should establish procedures to manage and maintain integrity of storage wells and reservoirs in accordance with the requirements of other sections of this standard.

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11.8.2 Scope of Procedures

The operator should develop procedures related to integrity and risk management that define the frequency or interval of review, data or information to be reviewed, and methods of data trending or normalization.

11.8.3 Review of Procedures

The operator should evaluate such factors as well and reservoir integrity performance and the number and types of issues that are occurring, as well as other issues, hazards, or threats that could require changing the frequency of future procedural reviews (e.g. new encroachments, third-party drilling).

11.9 Safety and Environmental Programs

11.9.1 General

The operator shall develop programs incorporating safeguards to the environment, site security, and safety and health into storage design, construction, and operations. The operator's programs should incorporate in a plan, or plans, operator-established procedures that are founded on industry recommended practices and applicable to process safety in storage operations.

11.9.2 Scope of Procedures

Plans and procedures addressing process safety can include:

— job plans;

— job reviews;

— job safety analyses;

— hazard analyses;

— risk mitigation;

— MOC; and,

— other procedures as deemed necessary by the operator.

The operator should verify that procedures address the conduct of work in a manner that minimizes environmental and safety risks.

11.10 Public Awareness and Damage Prevention

11.10.1 Scope

As required by regulations or as augmented by the operator, pipeline public awareness and damage prevention communications include information regarding the utilization of damage prevention notification systems, education of the public on the hazards related to unintended releases, indications of a release, procedures for reporting the release, and actions to be taken for public safety during the release.

11.10.2 Coordination of Programs

The storage operator should coordinate with existing pipeline public awareness and damage prevention plans where possible to address storage-specific communications that may include information such as well setback limits, encroachment and land use policies, or other information that could affect storage well or reservoir integrity.

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11.11 Management of Change

11.11.1 General

Revision of procedures and processes is an acceptable practice, but the operator shall require changes to be accomplished in a controlled manner. The program documentation, framework, and procedures shall be revised before the change can be implemented. Not all changes need be approved through a formal MOC process. Some changes are expected and may not be subject to a formal change control process. The operator should define the types of changes determined to be significant and requiring a MOC.

11.11.2 Scope

The operator should develop and maintain a MOC process that addresses changes in equipment, processes, materials, or procedures. The MOC process should include procedures to identify impacts associated with changes and determine the effect of the change on the storage facility. The MOC process should address approval authority and responsibility for the change and document implementation of the change.

A MOC procedure should include a process for approval of deviations from the procedures when necessitated by abnormal/emergency conditions.

The operator should update procedures, communicate and document changes to procedures in accordance with the operator's MOC process, and verify that personnel engaged in operating and maintaining the storage reservoir and wells are aware of and trained in those changes.

11.12 Training

11.12.1 Training Requirements

The operator should provide training for personnel responsible for operating, maintaining, and monitoring storage wells and reservoirs in accordance with their duties and responsibilities.

Training should address procedures specified in Section 11, safety procedures, recognition of abnormal operating conditions, and emergency conditions. Training programs may consist of various methodologies including but not limited to classroom, computer-based, and on-the-job training.

Training programs should be reviewed periodically to determine effectiveness.

The operator should modify training programs when changes occur in technology, processes, procedures, or facilities.

11.12.2 O&M Personnel

The operator should confirm by training and testing that persons assigned to operate and maintain storage wells and reservoirs possess the knowledge, skills, and abilities necessary to carry out their duties and responsibilities including those required for start-up, operation, and shutdown of storage facilities.

Personnel should be trained on the site-specific procedures necessary for operation of storage wells and reservoirs.

Personnel should be trained on the recognition of abnormal operating conditions.

Personnel should be trained on reporting requirements, documentation, and recordkeeping requirements.

Whenever changes are made to the operating procedures specified in 11.3, operating personnel shall be notified and trained as necessary in the changes and training documented before operating storage wells and reservoirs.

The operator should provide refresher training on a periodic basis to ensure that personnel understand and adhere to current operating procedures.

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11.12.3 Supervisory Personnel

Specific job requirements may require the company person or persons directly responsible for the work being conducted ("supervisors") to be located on site while the work is being conducted (see 6.10).

A supervisor should be qualified to provide competent and effective supervision of the operations being carried out.

A supervisor should confirm that personnel on site can recognize abnormal operating conditions and applicable hazards and know their role in safety and emergency procedures.

A supervisor should confirm that operating and contractor personnel conducting gas storage well and reservoir operations are qualified to perform the work.

A supervisor should verify that operating and contractor personnel understand and adhere to reporting requirements in the operator's procedures.

11.12.4 Contractor Personnel

The operator may use contractor personnel in the performance of constructing, operating, maintaining, and monitoring duties associated with storage wells and reservoirs. This subsection provides recommendations regarding training of contractor personnel.

The operator should provide and specify the scope of work to be performed by contractors.

The operator should define minimum qualification or experience requirements for contractors performing work on their storage wells and reservoirs.

The operator should develop a method to verify contractor training, which may include a review of the contractor's safety training programs, worksite checks of individual contractor employee training, or operator observation of contractor work performance.

The operator should provide copies of the appropriate current procedures and review those procedures with contractors prior to any work being performed, and ensure that persons performing work in the storage field are familiar with the procedures and recordkeeping requirements.

The operator should provide training to contracted personnel that includes applicable site-specific safety procedures, awareness of rules pertaining to the facility, reporting requirements, and the applicable provisions of emergency action plans.

11.13 Records

11.13.1 Documentation

The operator shall maintain records to document establishment of and compliance with procedures as required in Section 11. Records may be kept in an appropriate format (paper or electronic). The integrity of the records, especially electronic, should be verifiable. Records should include superseded procedures.

11.13.2 Training Records

The operator shall maintain records that demonstrate compliance with this subsection.

Company personnel training records should include:

— identification of the trained individual;

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— identification of the training and methodology of training provided; and

— date(s) training was completed by the individual.

Contractor Training Records—The operator should retain documentation of the contractor training review (see 11.12.4).

11.13.3 Retention

The operator shall establish retention intervals for records that meet regulatory requirements; where no regulatory requirements exist, retention intervals should be determined by the operator.

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Ex. I - 5

AC 0026

INTEROFFICE CORRESPONDENCE

CALIFORNIA gas COMPANY

TO * See Below FROM R. D. Phillips DATE July 31, 1989

SUBJECT Project Approval Letters

* D. R. Horstman
M. E. Melton
S. P. Robinson

Attached are revised Project Approval Letters from the D.O.G. The D.O.G. modified their original approval letters as we requested at the annual review meetings in June. Specifically, the onerous requirements of calibrating test gauges has been greatly softened (see Stipulation #4 on the attached). The stipulation now states that pressures are measured and recorded weekly and that evidence of such measurement and calibration must be made available to them upon request. I interpret this to mean that we can continue taking and recording pressures has we now do and continue with our existing calibration procedures.

Stipulation #9 was also changed as we had requested. Graphs of oil, water and gas production rates vs. time are now required for the entire zone rather than for each well has originally required.

RDP:ds
Attachment

cc: N. D. Stevenson
R. W. Weibel

STATE OF CALIFORNIA-RESOURCES AGENCY GEORGE DEUKMEJIAN, Governor

DEPARTMENT OF CONSERVATION
DIVISION OF OIL AND GAS
6401 TELEPHONE ROAD, SUITE 240
VENTURA, CALIFORNIA 93003-4458
(805) 654-4761

April 18, 1989
Revised July 26, 1989

R.W. Weibel, Agent
Southern California Gas. Co.
810 S. Flower St.
Los Angeles, CA. 90017

GAS STORAGE PROJECT
Aliso Canyo
Sesnon-Frew Zone

The Division of Oil and Gas has responsibility for wells that inject and withdraw natural gas from an underground storage facility. Our records indicate that, although individual wells have been permitted, project approval has not been issued by the Division to conduct underground gas storage operations in the Aliso Canyon field. Therefore, continued operation of the project is approved provided that:

1. Form OG105 or Form OG107 is used whenever a new well is to be drilled for use as an injection-withdrawal well, observation-collection well or whenever an existing well is to be converted to an injection-withdrawal well or observation-collection, even if no work is required. (Specific requirements will be outlined in our answer to your notice.)

2. When an existing well is to be converted to injection-withdrawal or observation-collection, a test is conducted to demonstrate the mechanical integrity of the casings.

3. A monthly injection-withdrawal report is furnished to this division listing the amount of gas injected, injection pressure, and amount of gas withdrawn from each well.

4. Surface pressures on each active or idle well are measured weekly with a calibrated test gauge, and recorded. Evidence of such measurement and calibration must be made available to this Division upon request.

5. All injection piping, valves and facilities meet or exceed design standards for the maximum anticipated injection pressure and are maintained in a safe and leak free condition.

6. The gas storage reservoir pressure shall not exceed 3600 psi. Tests may be required to establish that no damage will occur from excessive injection pressures.

Southern California Gas. Co.
Aliso Canyon

7. A mechanical integrity test is made and filed with this Division for each injection-withdrawal well within three months after injection and/or withdrawal has commenced, at least once every year thereafter, after any significant anomalous rate or pressure change, or as requested by this office to confirm that the stored gas is confined to the intended zones.

8. A Division approved monitoring program plan is installed for the gas storage zone. Data shall be available for periodic inspection or as requested by the Division.

9. The following data are maintained for surveillance and evaluation of the project and are made available for periodic inspection by personnel from this Division:

   a. A graph of oil, water, and gas production rates vs. time for each zone.

   b. A graph of reservoir pressures, gas inventory fluctuations, and injection pressures.

   c. Observation well data, reservoir fluid distribution, temperature, radioactive tracer, and noise surveys.

10. Upon request, the Division is provided with any other data deemed necessary to monitor the operations of the project.

11. The Division is notified of any anticipated changes in a project resulting in alteration of conditions that were originally approved, such as: increase in size of the project, increase in the approved zone pressure; changes in the injection-withdrawal intervals; changes in the observation-collection intervals; or monitoring procedures. Such changes shall not be carried out without Division approval.

12. Any remedial work in the project area necessary because of the gas storage operation on idle, abandoned, or active wells needed to protect life, health, property and oil, gas, or freshwater zones will be the responsibility of the project operator.

13. Injection-withdrawal operations shall cease if any evidence of damage is observed or upon written notice from this Division.

Sincerely,

Patrick J. Kinnear
Deputy Supervisor

Ex. I - 6

Tubing and Packers in Underground Natural Gas Storage: Safety and Reliability Considerations

AGA/API/INGAA Underground Natural Gas Storage
Joint Industry Task Force

Shared by: Anders Johnson, Kinder Morgan & JITF
Nashville, Tennessee
September 16, 2016

DRAFT

Agenda

- Definitions
- Executive Summary
- JITF Tubing and Packer Considerations
- Conclusions
- Questions

Definitions

- BOP — Blowout preventer
- Collar — Internally threaded pipe used to join two pipes
- Gravel Pack — Gravel/screens at the bottom of the well that prevent sand from flowing up the well
- Packer — Expanding mechanical device that engages casing
- Slips — Mechanical jaws that engage the casing to prevent the packer from slipping
- Tubing — Screwed pipe joints, 30’, coupled together to for a downhole tubing

Executive Summary

- Tubing and packer deployments are operationally beneficial in cases where the operator has designed the tubing/packer system to: isolate different production zones, increase gas velocity for liquid lift, convey a SSSV in high risk areas, and/or protect the surface casing from conditions such as scaling.
- Tubing/packer installations in existing wells can be problematic because: 1) the wellhead must be adapted to support the tubing, 2) once hung tubing prevents the casing in gas wells from being internally inspected without removing the tubing, 3) the tubing installation in an existing well may reduce flow by more than 60% and require the operator to drill additional wells to meet market peak delivery requirements.
- The benefits of tubing and packer in an existing well may be de minimis because of the increased risks and costs of installing and removing the tubing, considering that gas storage well failures in the U.S. are very unlikely[1] and that there are inspection techniques to improve the understanding of well integrity.
- Adding tubing to an existing well adds 51 – 267[2] potential leak points and decreases critical day deliverability. Tubing is not generally reused because of the increased leak potential from damaged threads during extraction thus adds cost without benefit.
- Regulations requiring frequent inspection of the casing increase the likelihood of a catastrophic incident due to the extraction and then re-installation of new tubing and packers each time the casing is inspected.
- Sound well design and a risk based well integrity program following API 1170/1171 guidelines should be applied to all tubing and packer installations.

[1]JIFT White paper July 2016
[2] 1500' well has 50 pipe joints, an 8000' well has ~267 pipe joints and one packer

Joint industry Task Force

- AGA-API-INGAA Joint Industry Task Force White Paper
- Represents 200,000 well-years of operating experience
- ~17,500 onshore gas storage wells
- ~13% of the existing gas storage well have tubing/packer completions
- Tubing packer failure rates reported from operators based on anecdotal experience are averaging less than 4e -4 well year failure rate over 20 years
- Re-entry and replacement rates for failed tubing and packer are less than 0.1 entries per well-year but comprise a real risk as the tubing may need to be pulled while the well is pressurized
- 100% of tubing and packer redress/replacement has been reported for every well re-entry containing tubing and packer by several of the major storage operators

Underground Natural Gas Storage JITF White Paper
http://www.energyinfrastructure.org/energy-101/natural-gas-storage

Concerns with Tubing and Packers in Existing Wells

Storage wells were not designed to accommodate tubing and packer in many cases, WH master valves cannot be closed if the tubing is hung above the master valve

Design and Construction

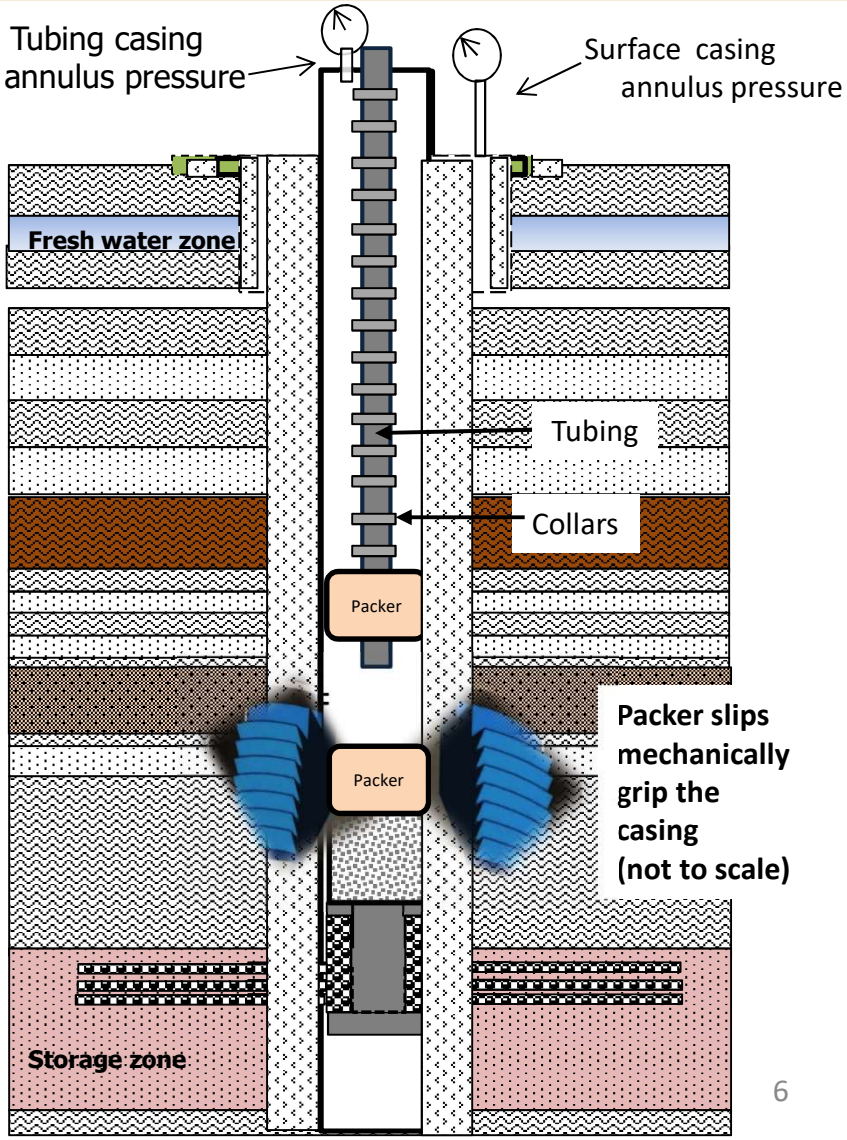
- Wellheads must be replaced and/or rebuilt to accommodate the dimensional changes of tubing hangers, wells will be out-of-service, and loss of delivery must be replaced.

Risk

- Greatest risk for an accident is during intervention
- Advanced tools such as High Resolution Vertilog cannot be used to analyze the condition of the casing when tubing is present
- Packer slips apply thousands of pounds of force into the casing and leave indications in the pipe wall
- Scale and ovality allow gas to leak around the packer
- Velocity induced erosion must be monitored

Deliverability

- Well flow on the peak day may be reduced >60% in some wells resulting in the inability to meet peak demand without drilling new wells which increase the number of leak points and future interventions



Limited Applications of Tubing and Packers in Existing Wells

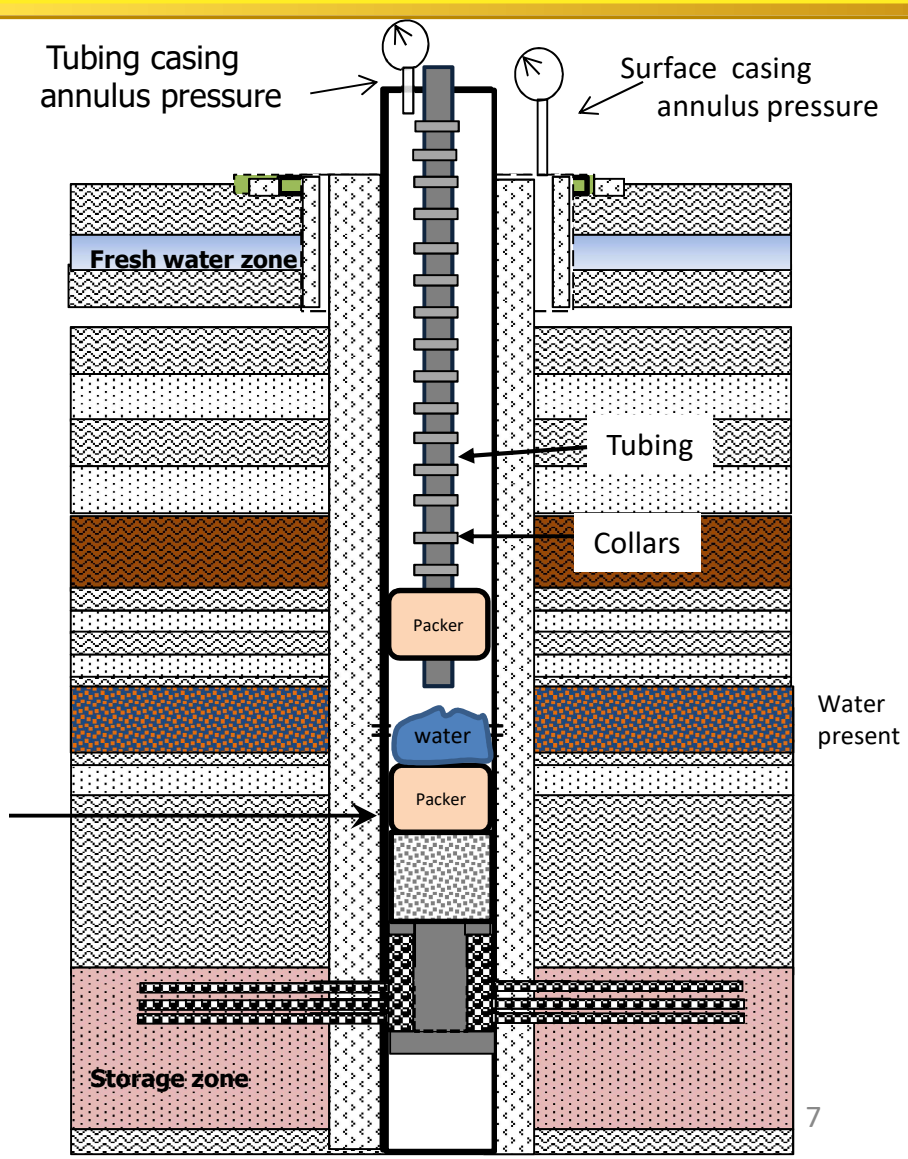
Underground Gas Storage wells were not designed to accommodate tubing and packer in many cases; however modifications are possible in larger diameter casings.

Design and Construction

- Wellheads must be replaced and/or rebuilt to accommodate dimensional changes of tubing hangers

Situational Operations Applications

- Preventing wells from watering off: Reduced flowing area in the tubing results in higher gas velocity enabling water and gas withdrawal as opposed to flow going to zero when the well fills with water
- Casing Concerns: Known casing anomalies can be ameliorated with tubing, reduction of casing pressure and monitoring of annulus pressures to detect issues
- Isolation requirements: Tubing and Packers can be used to isolate zones that are no longer required



Example of a Workover Rig

Installing /removing tubing from a well usually requires site preparation and workover rigs to handle thousands of pounds of steel. One of the greatest risks to people and the environment is the installation and removal of the tubing and the packer. Packers can seize in the well and require destructive milling to remove and re-establish the well bore

Tubing Flow Reduction = Loss of Delivery

Indicative flowing area restrictions resulting from installation of tubing into a production casing

Casing Diameter (inches)	Casing ID inches	Nominal Tubing Diameter	Flow Area Reduction
4-1/2”	3.5	2-3/8”	**54%**
5-1/2"	4.6	2-7/8”	**61%**
6 5/8"	5.7	3-1/5”	**62%**
8-5/8”	7.7	5-1/2”	**49%**
9-5/8”	8.4	7”	**31%**
13-3/8”	11.7	9-5/8”	**32%**

Flow is a function of temperature, cross-sectional area, and pressures Q f(t, a, P) in general a reduction in cross sectional area causes a pressure drop which reduces flow. Each field must be carefully examined, considering delivery requirements and critical day pressures. As the storage field pressures drop with declining inventory the flow impact of the reduced flowing area (tubing) becomes more detrimental. Some storage operators may see practical deliverability go to zero on critical flow days because of the restricted flow area and resulting pressure drop caused by the high gas velocities in the tubing.

Installing Tubing and Packers in Existing Gas Wells

Installing tubing and packer in an existing well

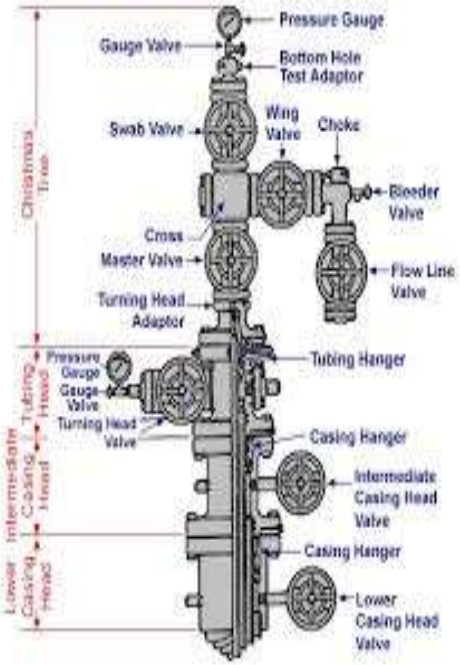
- Requires killing the well for 3–5 days, preparing the site for disturbance
- Trucking in workover rig, water, pumps, tanks , tubing, packer
- Removing wellhead and installing Blowout Preventer, BOP
- Re-building the wellhead, adding tubing hangers, re-welding piping connections that will be no longer aligned because of dimensional changes
- Cutting existing connecting piping and relocating shut-off valves
- Increased personnel on site for installation and extraction
- Increases well maintenance requirements and environmental exposure
- Decreases well deliverability, causes pressure drop and may require plugging and abandonment of marginal wells
- If excess field /well capacity is not available new wells must be drilled to meet peak day system needs driving up environmental exposure and risk

Cost of Down Hole Tubing

Adding tubing and packer to all competent wells adds Billions of $ of added capital cost with limited proven benefit and increases risk during installation and removal.

Nominal Tubing Diameter	Estimated Installed Cost
2-7/8”	$130,000*
5-1/2”	$215,000*
7”	$250,000*

*Estimates based on one set of conditions assuming nominal tubing sizes . Costs will vary, possibly more than +/-50% depending on site requirements



Source: m.blog.daum.net

Notes:
Approximately 15,000 storage wells do not have tubing and packers isolating the casing[1]
Tubing installation requires modifications to the existing wellhead and piping

AGA Underground storage survey[1]

Conclusions

- Proactive Well Integrity Programs are the best method of preventing unintended gas loss; multiple well barriers (casing/cement) mitigate risks. Tubing and packer are not needed in a well if the casing and cement were properly designed and installed
- Adding tubing adds a barrier within the well but also adds physical risks to people, increases environmental risk every time it is installed and removed, and reduced deliverability
- Tubing consists of screwed pipe joints and therefore adds potential leak points
- Tubing must be removed from the well to inspect the casing and increases the risk of a catastrophic incident while thousands of pounds of steel are pulled from a well under pressure
- Packers are mechanically expanded downhole and exert thousands of pounds of force on the casing. Packers may damage the casing and most operators do not set a packer in the same location because of the damage caused by the slips
- Regulations requiring frequent inspection of the casing increase the likelihood of a catastrophic incident associated with increase in well interventions to extract and then re-install new tubing and packers. (Tubing is not generally reused because of the increased leak potential from damaged threads during extraction).
- Conformance with API 1171 “shalls” provides a consistent and thought-out risk based approach that can be implemented over 7 – 10 years with the greatest risk situations being addressed within the first 5 years

Appendices

- Poll of U.S. Underground Natural Gas Storage Operators indicates that approximately **13%** of existing gas storage wells have tubing and packer installed within the well bore - September 2016

- I/W Wells reported: 13,485* out of an estimated 17,500
- Active Storage Wells: 11,411
- Observation Wells: 2,320

- Wells with Tubing and Packer
  - Active Storage Wells: 1,302
  - Observation Wells: 417

*Estimated 80% response rate based on the number of reported wells

Ex. I - 7

Environmental Research Letters

LETTER • OPEN ACCESS

A national assessment of underground natural gas storage: identifying wells with designs likely vulnerable to a single-point-of-failure

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LETTER

A national assessment of underground natural gas storage: identifying wells with designs likely vulnerable to a single-point-of-failure

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Keywords: underground natural gas storage, natural gas supply chain, methane, Aliso Canyon, climate change, risk assessment, wellbore integrity

Supplementary material for this article is available online

Abstract

The leak of processed natural gas (PNG) from October 2015 to February 2016 from the Aliso Canyon storage facility, near Los Angeles, California, was the largest single accidental release of greenhouse gases in US history. The Interagency Task Force on Natural Gas Storage Safety and California regulators recently recommended operators phase out single-point-of-failure (SPF) well designs. Here, we develop a national dataset of UGS well activity in the continental US to assess regulatory data availability and uncertainty, and to assess the prevalence of certain well design deficiencies including single-point-of-failure designs. We identified 14 138 active UGS wells associated with 317 active UGS facilities in 29 states using regulatory and company data. State-level wellbore datasets contained numerous reporting inconsistencies that limited data concatenation. We identified 2715 active UGS wells across 160 facilities that, like the failed well at Aliso Canyon, predated the storage facility, and therefore were not originally designed for gas storage. The majority (88%) of these repurposed wells are located in OH, MI, PA, NY, and WV. Repurposed wells have a median age of 74 years, and the 2694 repurposed wells constructed prior to 1979 are particularly likely to exhibit design-related deficiencies. An estimated 210 active repurposed wells were constructed before 1917—before cement zonal isolation methods were utilized. These wells are located in OH, PA, NY, and WV and represent the highest priority related to potential design deficiencies that could lead to containment loss. This national baseline assessment identifies regulatory data uncertainties, highlights a potentially widespread vulnerability of the natural gas supply chain, and can aid in prioritization and oversight for high-risk wells and facilities.

Introduction

Each year nearly 28 000 billion standard cubic feet (Bcf) of processed natural gas (PNG) composed primarily of methane (CH_4), ethane (C_2H_6), other hydrocarbons, and sulfurous odorants flow through the US natural gas supply chain. Approximately 13% of PNG produced annually is injected back into underground storage reservoirs, which are either depleted hydrocarbon fields, depleted aquifers, or solution-mined salt caverns [1]. Underground natural gas storage (UGS) facilities contain 4300 Bcf in working capacity and provide a critical link in PNG operations as they bridge imbalances between supply

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and demand and mitigate ratepayer cost volatility [1–3]. Domestic natural gas production has grown 50% in the past decade and PNG storage has recently reached all-time highs [4]; however, the 2015 Aliso Canyon UGS incident has prompted new scrutiny of the nation's natural gas storage infrastructure [3].

Between October 2015 and February 2016, an estimated 99 638 (± 9300) metric tons (mt) (5.0 Bcf) of methane were released into the atmosphere from a failed storage well operating at the Aliso Canyon UGS facility near Porter Ranch, California [5, 6]. The 118-day leak resulted in the evacuation of 5790 households, and has raised new health concerns for proximate populations [7]. The emissions from the incident constitute the single greatest accidental release of climate forcing gases in US history [6] and accounted for 2.0 million metric tons of CO_2 equivalent, or about 6% of the 2015 US natural gas transmission and storage emissions from the US Environmental Protection Agency's (EPA) Greenhouse Gas Inventory (GHGI) [8]. If incorporated into the GHGI, this single incident would increase the methane emissions attributed to storage wells by 770% from the 1999–2014 baseline of 14 879 mt yr^{-1} [9].

Unintentional gas migration from UGS operations has caused fatalities, fires and explosions, evacuations, exposure to noxious odors, tropospheric ozone production [10], and releases of climate-forcing gases [11, 12]. A 2009 review of underground gas storage incidents cited 200 unintended gas migration events in the US to date [13]. The majority of unintended releases at UGS facilities, including the Aliso Canyon release, were associated with well integrity problems [11–17] (supplementary information (SI) available at stacks.iop.org/ERL/12/064004/mmedia). Presently, well-level data on incidents is not widely available and is inconsistently reported among states, limiting the opportunity to assess the rate of UGS well failure risk [13, 17].

The Aliso Canyon #25 Standard Sesnon (#25 SS) well failure is believed to have originated from the subsurface well casing [3, 18]. The well—originally completed in 1954 as an oil-producing well and repurposed for UGS in 1972—was vulnerable to a single-point-of-failure (SPF) along a portion of its production casing because: (1) a single full-length well casing was exposed directly to the outside rock formation from 990–6960 ft.; (2) gas was intentionally moved through both the outer well casing, and the inner production tubing (SI text). Injecting and withdrawing gas through both the production tubing and casing was a common practice at Aliso Canyon and has recently been identified as a common practice at other UGS facilities, particularly at older wells [3], which typically have narrower pipe diameters. An additional factor that may have contributed to loss of containment was the removal of a sliding sleeve valve in 1979 that was intended to provide a connection between the tubing and the tubing-casing annulus [3]. From industry surveys, only 3%–5% of active UGS wells utilize safety valves or sleeves below the surface [19]. The combination of these factors effectively bypassed the passive barrier protection provided by the inner production tubing, rendering the well's structural integrity commensurate to that of a single casing at 990–6960 ft.

Following the Aliso Canyon incident, the 2016 Protecting our Infrastructure of Pipelines and Enhancing Safety (PIPES) Act mandated that the Pipeline and Hazardous Materials Safety Administration (PHMSA) promulgate minimum Federal standards for UGS operations by June 22, 2018 [18]. The Interim Final Rule (IFR)—Pipeline Safety: Safety of Underground Natural Gas Storage Facilities notes that the lack of minimum downhole regulations at UGS facilities presents an immediate threat to safety, public health, and the environment [20]. Some states had adopted regulations, but only for 'in-state' facilities that do not send gas into the interstate market [49 U.S. C. § 60104(c)]. Several states have no safety regulation for UGS facilities, and others only regulate facilities in specific geologies (e.g. salt caverns) [3]. Following the Aliso Canyon incident, California has amended design, construction, and maintenance measures to help ensure that current SPF wells do not pose an immediate threat of loss of control of fluids [21]. To inform PHMSA's rule-making process, an Interagency Task Force (ITF) on Natural Gas Storage Safety was formed to study three primary areas of concern: integrity of UGS wells, public health and environmental effects from natural gas storage leaks, and energy reliability. One of the highest priority recommendations regarding well integrity was to ultimately phase out UGS well with SPF designs [3].

Modern production and UGS wells typically contain a nested set of structural elements (e.g. casing, tubing, cement, packers, and wellheads) to form multiple barriers that collectively function to achieve zonal isolation [22]. According to the IFR, an uncertain portion of active UGS wells, like the #25 SS, are repurposed production-type wells that are facing obsolescence issues, and likely exhibit vestiges of original construction (e.g. lack of corrosion-resistant coatings) [20]. Therefore, based upon common practices prevalent during previous well construction eras [23], a portion of repurposed UGS wells may be particularly likely to exhibit designs vulnerable to SPF. Additionally, wells not designed for UGS are also more likely to lack corrosion-resistant coatings, utilize threaded pipe couplings, and exhibit insufficient strength safety margins for steel casings [20].

Identifying the prevalence of wells with design deficiencies such as single barriers would reduce vulnerability of UGS systems. Despite forthcoming regulations and reliance on UGS, baseline well-level information is not readily available, and according to the IFR, there is currently no effective means to ensure compliance with safety standards [20]. The absence of

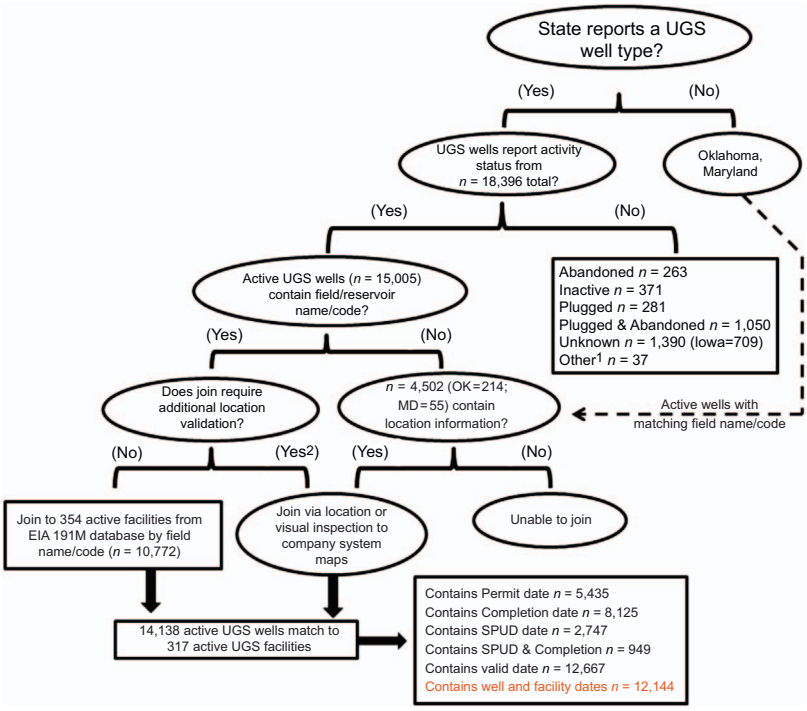

Figure 1. Framework to join UGS well and facility records. [1]Other status types include 'not completed,' 'not yet in storage service,' 'out of service,' and 'authorized but not drilled' [2]UGS well data from eight states required additional inspection to verify join to facility (see SI table 3)

such data impairs a systematic risk assessment and stakeholder management of UGS, along with refinement of EPA's GHGI [9, 24]. Improving our understanding of disparate state and Federal UGS wellbore data can aid in reducing uncertainties, and methods presented herein provide a tractable approach towards baselining national UGS well-level activity.

Here, we develop a national dataset of UGS well activity in the continental US to assess regulatory data availability and uncertainty, and perform a first-order assessment of well-level design deficiencies. To do so, we develop a framework to join disparate Federal- and state-level UGS data, and apply an indicator method to identify repurposed wells and those more likely to exhibit a SPF well design.

Methods

Storage field data

The Energy Information Administration of the US (EIA) maintains the *Oil and Gas Field Code Master List,* which provides standardized field names and codes for all identified oil and gas fields in the US [25]. We relied on the April 2016 EIA-191 M *Monthly Underground Gas Storage Report* to identify active UGS operations and matched these operations with state-level well data [1]. The EIA aggregates UGS operations by field and reservoir codes. However, not all states adhere to consistent distinctions between subterranean fields and reservoirs. Moreover, a portion of UGS operations reported by the EIA contain either duplicate field or reservoir names/codes, which indicates co-located operations within a single facility. Therefore, we include counts of unique UGS 'fields/reservoirs' and 'facilities' containing multiple co-located field-reservoirs where applicable. For interpretability, we refer to 'fields' hereafter as the subterranean entities as implied in the EIA 191 M list, whereas 'facilities' refer to UGS operations that have been joined to wells as per our methods described herein (see figure 1).

Storage well data

For most states, UGS well data were available via web download. Four states required academic use agreements via direct correspondence (SI table 3). The 'well type' variable was the primary indicator of a storage-related function [e.g. storage, injection (gas), monitoring storage]. Well types not explicitly related to PNG storage, such as liquefied gas storage, were excluded. To determine activity state, most states provided a 'status' indicator (e.g. active, plugged and abandoned, inactive, shut-in, etc.) that was used to determine the current activity state of a well.

Well-to-field join

Under the assumption that active storage wells and storage fields coincide, we attempted to join wells and fields based upon the availability and quality of well records. The data joining process is displayed in figure 1. Where applicable, well data were standardized using geodatabase aggregation and included location information, type, status, activity dates, depth, an indicator of whether a well was assigned to a facility, and unique state-well identifier (e.g. API #).

Determining well construction date

Well construction dates were generally included in state databases. We compared spud dates—the date of initial ground penetration—with permit and completion dates to determine whether completion or permitting reflected the original completion or permit, or subsequent re-completions or re-permitting. Completion occurred within a year of the spud date in 92% of 949 wells for which both spud *and* completion dates were available (SI figure 2), which suggests that these completion dates obtained largely reference the original completion of the well. Based on this relationship, we assigned the year of the oldest activity date for each well to proxy as the year of original construction.

Identifying well-level deficiencies

Repurposed storage wells were defined as wells that were originally designed for hydrocarbon production (or other non-UGS function) and were later converted to storage. To determine whether a well was designed for storage or repurposed, we compared the well's construction date to its associated field storage designation date. The storage designation date (when the facility began injecting PNG) was obtained from the *2013 Oil and Gas Field Code Master List* [25] (the most recent edition containing designation years). We examined the entire distribution of well construction dates in relation to their respective facility designation dates. From these observations, wells that predate their facility designation date by at least three years were treated as repurposed, and wells within two years of facility designation date, were treated as designed for storage.

Confirmation of SPF design would require individual well histories, which are not readily available at the national scale. Therefore, we employed an indicator method to identify well-level deficiencies inferred from initial well use, and common construction practices at the time of drilling. Based upon recommendations by the ITF, we chose a well construction date of pre-1979 to indicate the likelihood of a SPF design [3]. Therefore, repurposed wells with a construction date before 1979 were classified as particularly likely to exhibit a SPF design. We also utilized well construction eras from King and King [23] to provide context in identifying other potential well-level design deficiencies. We also compared well depth to well age to help corroborate initial well use, and to provide an internal data validation within state.

Results

Data quality and completeness

As of July 2016, the EIA reported 384 active and 23 inactive underground gas storage field-reservoirs associated with 131 unique company names within the continental US. Of these 384, 18 contained at least one duplicate field name or derivative (e.g. Lee 2; Lee 8; Lee 11) totaling 48 entries. Thus, the 384 active field-reservoirs were contained within 354 geographically confined UGS facilities. We identified 18 396 total UGS-related wells, with 14 138 'active' status UGS wells successfully joined to 317 active UGS facilities in 29 states (figure 1). Thus, 37 active UGS fields were unable to be joined to a single active UGS well. The counts above exclude the four Alaskan facilities and the 82 UGS facilities that have been abandoned, classified as inactive, or are no longer in use [26]. Of the 14 138 active wells identified, 12 440 are sited in depleted fields, with 1561 sited in aquifers and 137 in salt caverns. Eighty-two percent (82%) of active UGS wells are located in the East and Midwest regions (figure 2), driven in part by the heavy dependence on UGS during the winter season. Of the inactive status wells, 1702 were reported as 'abandoned,' 'plugged,' or 'plugged & abandoned.' For more detailed state-level metadata see SI tables 3 and 4.

A portion of UGS wells ($n = 1390$) including all wells in Iowa ($n = 709$) and most Nebraska wells ($n = 103$) reported an 'unknown' activity status. Some of these wells were successfully joined by field name to active UGS facilities, indicting active operations. However, because the well activity status could not be verified, these wells were not included in final active UGS well counts. PA, NY, IA, MN, NE, and TX recorded 'unknown' as a potential well status.

A portion of states (14 out of 29) reported specific storage-well function (e.g. monitoring/observation, injection/withdrawal). Texas provided only injection-type storage wells coinciding with EPA's Underground Injection Control program, therefore withdrawal-only and monitoring wells were not enumerated. Oklahoma did not report a 'storage' well type, and only post-1984 wells were digitized and available for download as of February 11, 2016. These 15 states equated to 6483 total active UGS wells, with 1313 explicitly listed for injection, 695 listed for monitoring/observation, and the remainder listed as 'storage' excluding Oklahoma.

Ohio UGS wells data did not include field names/codes with well records; therefore, the 3318 UGS Ohio wells were joined geospatially to facilities via company system maps (figure 1, SI table 4). Eight other states had join discrepancies that necessitated further match validation by visual inspection of company system maps (figure 1, SI table 3).

Availability of well construction activity dates varied by state (SI table 3). Of the 14 138 active UGS wells identified, 12 667 or approximately 89% contained at least one relevant construction activity date (e.g. permit, spud, completion). Only 949 UGS wells reported at least two activity dates (see SI figure 2). Approximately 60% of wells included a completion date, 35% contained permit dates, and 18% had valid spud dates. Louisiana was the only state to

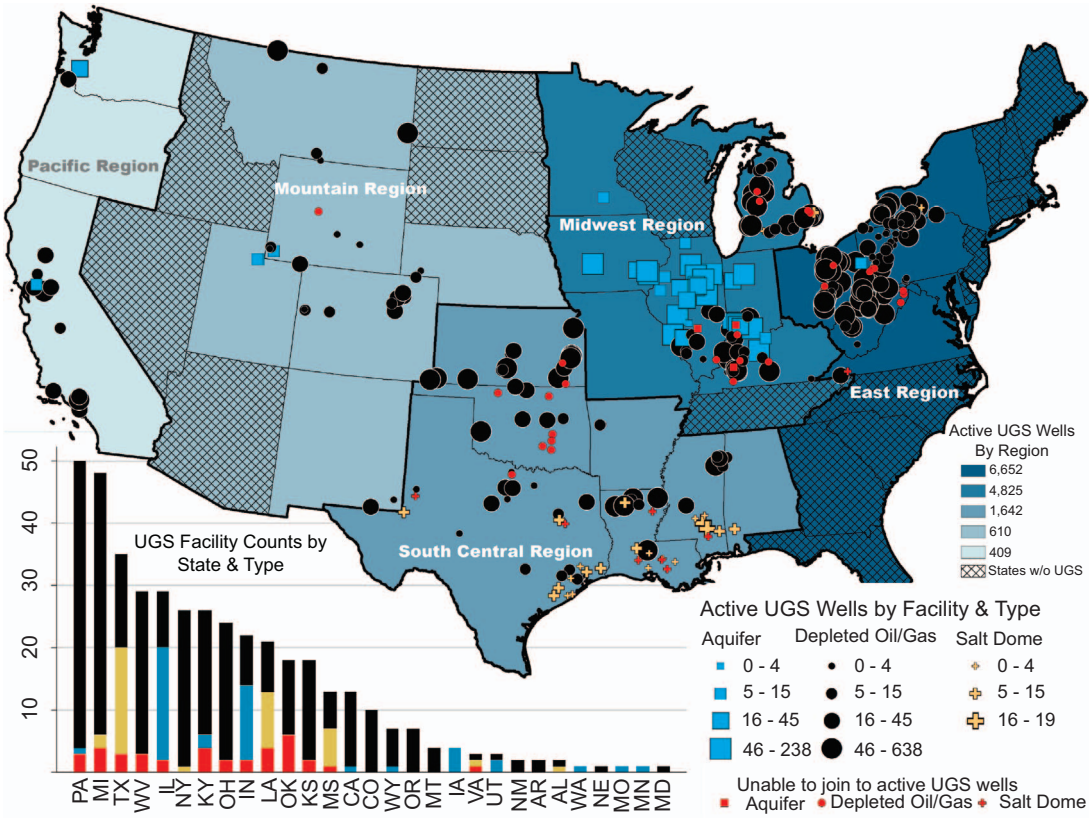

Figure 2. US underground natural gas storage facilities by geologic field type with number of active wells per facility (quantiles) and per region. In the bar graph and map, red represents the 37 fields that could not be joined to active UGS wells. Blue, tan, and black represent aquifer, salt dome, and depleted oil and gas facilities.

Table 1. Active UGS well counts by initial well use by facility-level category.

	UGS Wells[a]	UGS-Designed	Repurposed	Wells Missing Facility Date	Missing Well Date
Total	12 144	9429 (78%)	2715 (22%)	559	1471
Interstate	7021	5386	1635	255	673
Intrastate	5122	4042	1080	304	798
Aquifer	1151	1078	73	87	323
Depleted Field	10 950	8315	2635	428	1091
Salt Cavern	43	36	7	44	57

[a] reflects only active UGS wells that contain both well construction date and facility storage designation date.

provide a date for a workover-type event. Kansas did not report well construction dates for 330 active UGS wells—the most of any state—while Mississippi did not provide well construction dates for any of its 175 UGS wells. Notably, intrastate facilities, which connect to fewer wells than interstate facilities (5122 vs. 7021) have a higher rate of missing dates (table 1).

There are 76 639 entries in the *2013 EIA Oil and Gas Field Code Master List*, with 951 entries coded as 'STOR' in their remarks section indicating the field has been utilized for a storage function. Of these, 274 are listed as either 'unknown' or 'wildcat' fields across 18 states, and only 84 of the 951 indicate abandonment. Of the 354 active fields identified above, 337 reported the date the field began storage operations (designation date). The median designation year for these storage fields is 1963. Of the 12 667 wells with a valid construction date, 12 144 connect to a field that contained a valid storage designation date. Thus, well-level design deficiencies were assessed from 12 144 active UGS wells (see figure 1).

Overall, excellent well drilling depth data was provided by most states with 22 of 29 states reporting at least 95% coverage. Notable exceptions include Mississippi who did not report well depths and California with only 60% of wells reporting (SI table 3).

Well-level deficiencies

Comparing UGS well construction dates to their respective facility designation date reveals a peak of new well constructions that coincides with new UGS facility designations (figure 3). Of these, 1065 (9%) wells were constructed in the same year as their facility commenced storage operations, and 2633 (22%) of all UGS wells were constructed within the first two years of a UGS facility designation (figure 3). The increase in

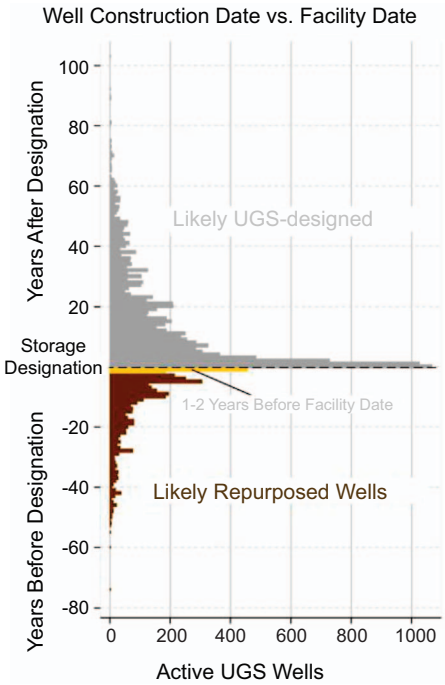

Figure 3. Number of wells (counts) constructed before and after its facilities' designation to storage date by relative years (well construction date subtracted from facility storage date).

well construction within the year prior to storage designation of their respective facility suggests that these wells were likely designed for the storage operations, or were re-completed for storage purposes. Data on well construction in the five years prior to facility storage reveal a local minima of new well construction at roughly two years before facility storage designation. While some wells constructed more than two years before storage designation may be designed for storage, a two-year cut-off of UGS-design wells is supported by the distribution of well construction relative to its facility designation in figure 3. Therefore, wells drilled at least three years before their respective facility storage designation date were classified as repurposed UGS wells.

Figures 4(*a*) and 4(*b*) rank facilities by storage designation date, and include joined active wells by construction dates. There are 114 active UGS facilities that contain only UGS-designed wells (active wells with construction dates after or within two years of the facility designation date). The shaded box in figure 4 (*a*) displays the 37 facilities that do not report a storage designation date, but did successfully join to active UGS wells with valid construction dates ($n = 559$). Though a portion of these wells may be repurposed, they were not included in final counts of repurposed wells. Figure 4(*a*) displays the 160 UGS facilities that contain at least one repurposed well.

Facility age and well age are positively associated, indicating that facility age helps to predict the distribution of well ages (Pearson's $r = 0.48$, $p = <0.0001$); however, facility age does not significantly predict of the presence of repurposed wells ($t = 0.031$, $p = 0.975$). Among facilities with at least one repurposed well, facility age is strongly correlated with well age (Pearson's $r = 0.72$, $p = <0.0001$). We observed that a majority of facilities continue to construct new UGS-designed wells after beginning storage operations, yet new well construction does not preclude operation of older, repurposed wells.

Of the 12 144 active UGS wells with adequate date information, 2715 (22% of 12, 144; 19% of active UGS wells) are classified as repurposed, of which 97% (2635) were sited in depleted oil/gas fields (table 1). An additional 266 wells with an 'unknown' status joined to an active facility would be classified as repurposed if the well status were to be confirmed. Thus, considering the 1994 active wells that did not contain valid well or field dates, and the 266 unknown status repurposed wells, the 2715 figure may underestimate the total number of repurposed UGS wells based upon this identification method. States that report an explicit storage well function account for 1135 of the 2715 repurposed wells; among these 241 were labeled as 'observation' or 'monitoring,' 41 were labeled as 'injection,' and the remainder were listed as 'storage.'

Repurposed wells are often older than UGS-designed wells (figure 5). The median age of repurposed wells is 74, compared to a median age of 48 years for UGS-designed wells and their age distributions are significantly different [X^2 (111, $N = 12\,129$) $= 7.2 \times 10^3$, $p < 0.0001$]. These results also reflect a decrease in UGS well construction over the last 30 years and a continued reliance on older wells.

Active repurposed wells can be found in 160 UGS facilities in 19 states, with 88% located in OH (902), MI (638), PA (370), NY (315), and WV (166) (figure 6). These 160 facilities connect to 79% of the total active wells and 51% of the working gas capacity in the US. Wells counts and locations of facilities with unknown status repurposed wells are indicated in gray in figure 6. Percent of wells missing sufficient date information to determine initial use is displayed in figure 6 at the state level (green pallet). Darker greens represent the percentage of wells either missing a well construction date or are connected to a facility missing designation date. Less than 10% of wells in OH, MI, PA, NY, and WV contain missing date information; however, universal activity date definitions are lacking.

An estimated 2694 of 2715 UGS repurposed wells were constructed prior to 1979, indicating these wells are particularly likely to exhibit SPF designs. Therefore, 99% of repurposed wells shown in figure 6 also meet our age-based indicator for exhibiting a SPF design, and with 88% constructed before 1960, there is a likelihood that these wells exhibit other well-design deficiencies as indicated in table 2. Notably, 661 active repurposed wells across 10 states were constructed before 1929—before well pressure-control systems and other containment methods were

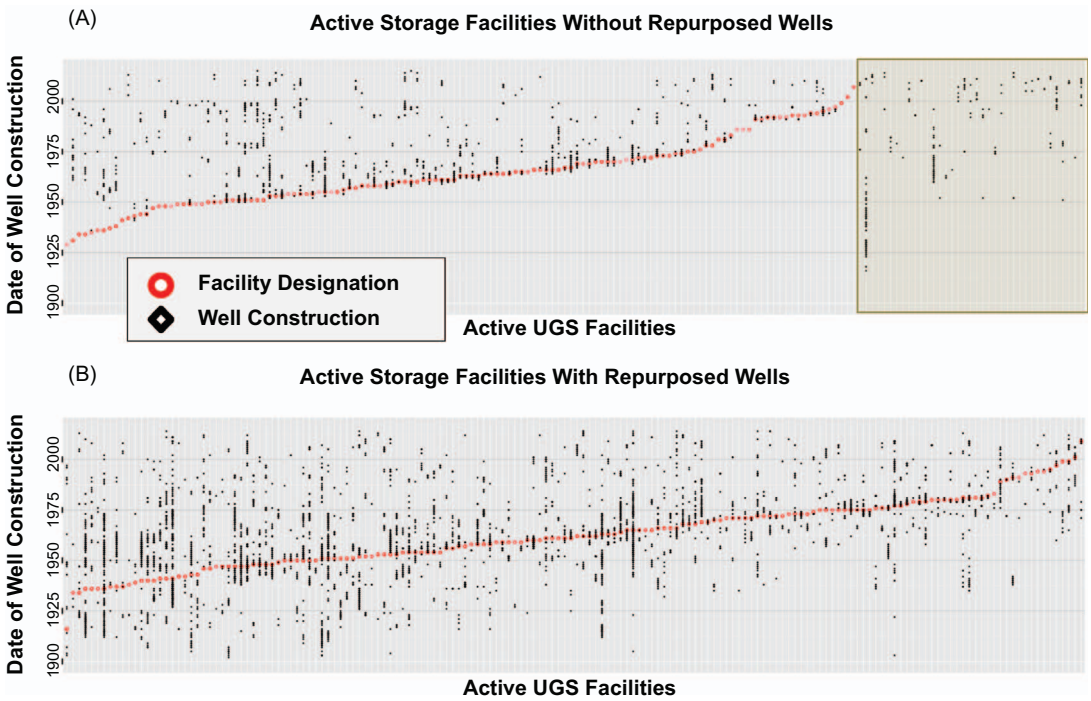

Figure 4. (*a*) Active UGS facilites with only UGS-designed wells. The gray-shaded box of figure 4(*a*) represents the facilities and associated wells where facility storage designation dates were not available. (*b*) Active UGS facilities with at least one active repurposed well as indicated by an individual well construction date predating facility storage operations by at least three years. Red circles indicate the date a facility began storage operations. Black diamonds indicate individual well construction dates.

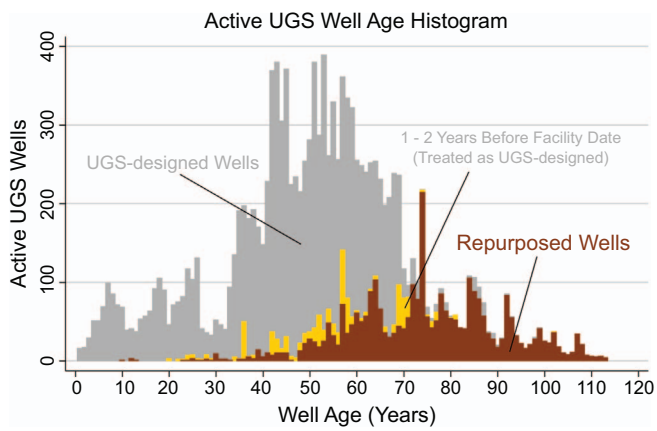

Figure 5. Active UGS well age distributions by year, colored by well design as per figure 3, with repurposed wells in dark brown, UGS-designed wells in gray, and wells drilled within two years before facility conversion to storage in yellow.

utilized. An estimated 210 active repurposed wells were constructed before 1917—before cement zonal isolation technologies were employed. These wells are located in PA, OH, NY, and WV and represent the highest priority related to potential design deficiencies that could lead to containment loss and should warrant further investigation.

Drilling well depth generally increases over time for all UGS wells ($r = -0.25$, $p = < 0.0001$) (figure 7(*a*)). However, this relationship is stronger for UGS-designed wells ($r = -0.38$, $p = < 0.0001$) compared to repurposed wells ($r = -0.19$, $p = < 0.0001$). While depth is associated with initial well design (repurposement), well age is a much stronger predictor of well design, explaining 37% of the variance compared to less than 1% for well depth. Nonetheless, well depth is important to consider in terms of wellbore integrity as pressures and temperatures generally increase with depth.

To further examine age and depth relationships, figure 7(*b*) categorizes repurposed wells by the top five states harboring repurposed wells. The clustering of wells by age, depth, and state particularly for MI, WV, and OH indicates a form of internal data corroboration between well depth and age variables. This concordance supports generalizability of findings related to initial use and design deficiencies at a state

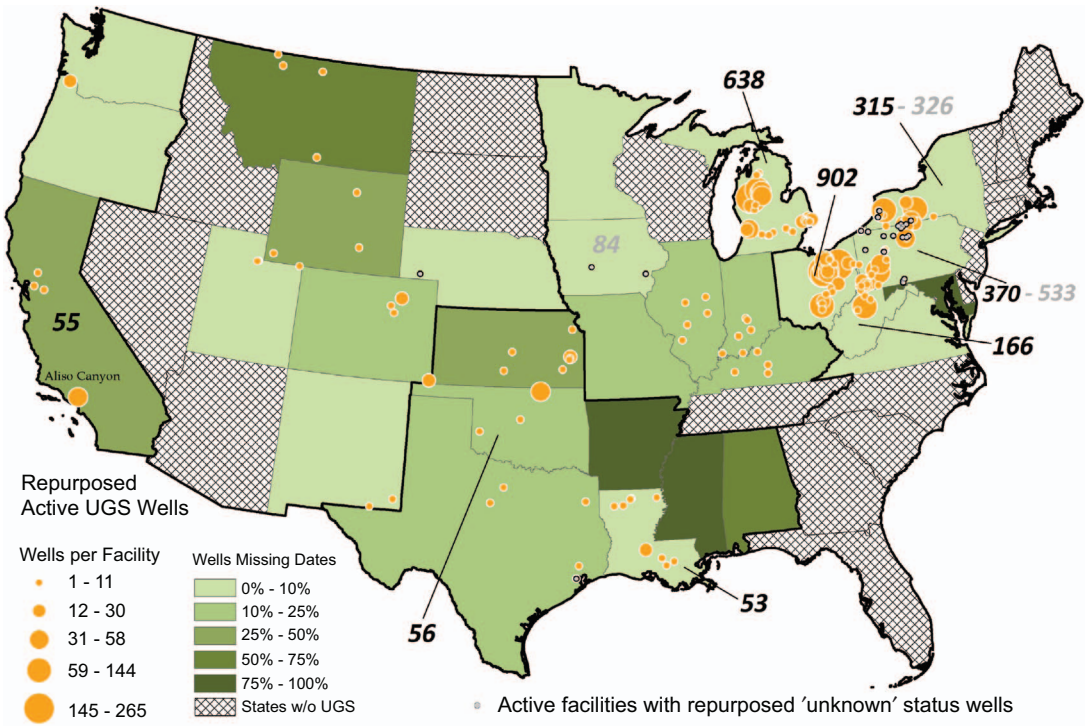

Figure 6. Counts of repurposed wells per facility symbolized by orange markers. Of the 2715 repurposed wells shown, 2694 (99%) were constructed prior to 1979, indicating a particular likelihood to exhibit SPF designs. Percent of active UGS wells missing sufficient date information is indicated at the state level by green shading. Gray markers indicate active facilities that contain at least one repurposed 'unknown' status well. Callout numbers represent counts of repurposed wells by state and includes active and unknown status well counts where applicable.

Table 2. Active UGS wells categorized by initial design and well construction eras adapted from King and King [23].

Time Era	Pre Zonal Cement Isolation (pre 1917)	Pre Well Containment (1917–1929)	Pre Gas Tight Couplings (1930–1959)	Pre Modern Cement (1960–1969)	Pre Additional Barriers; Cementing Full Strings (1970–2004)	Improved Well Integrity Assessments (2005–2015)	Total
Potential for pollution from well construction	High	Moderate	Moderate	Moderate	Lower	Lower	—
UGS-Designed	1	2	2683	2373	3938	430	9429 [a]
Repurposed	210	451	1737	214	103	0[b]	2715
Facility Date Unknown	1	45	102	70	172	133	523

[a] 1567 active wells did not contain a valid construction date.
[b] The youngest repurposed well was constructed in 1994.

level. In contrast, NY and PA wells tend not to cluster to the same degree, which may indicate greater geologic heterogeneity and historical drilling practices, or a higher degree of data uncertainty related to date information.

Discussion

This study presents an April 2016 census of active UGS wells concatenated from disparate state, federal, and company data and information, and provides a baseline for assessing obsolescence issues related to UGS wells. We document error sources, discrepancies across 29 separate wellbore databases, and highlight key limitations and areas in need of further investigation. State-level UGS wellbore datasets contained numerous reporting inconsistencies that limited data concatenation, and our attempt to characterize data quality and uncertainties adds to a limited literature on the subject [24, 27, 28]. Overall, the majority of state regulatory bodies harboring UGS operations provide public access to standard wellbore data and information, with certain exceptions related to download restrictions, paywalls, use waivers. UGS wellbore data from eight states contained important missing variables (e.g. field name, activity status, date information) that limited the well-to-field join

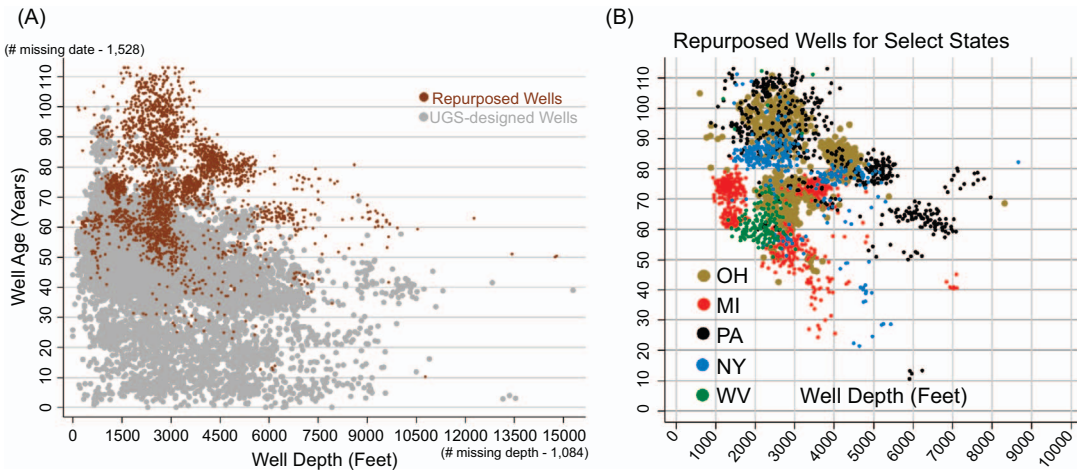

Figure 7. (*a*) Active UGS wells by age and depth below surface categorized by likely initial well design. (*b*) Repurposed wells colored by select states only by age and depth below surface.

process. Generally, these data variables were obtained following personal correspondence with data providers, with exceptions (see SI table 3). Most UGS wellbore datasets contained good coverage for: field name, status, location, operator, depth, one activity date, and API# where applicable. Generally, key missing variables included explicit storage well function, workover history, testing history, date types, and additional activity dates. Explicit characterization of well-level spatial uncertainty was beyond the scope of this study, though the peak signal between UGS field designation dates and well construction dates indicates a degree of temporal agreement between EIA field data and state well-level data. Similarly, documented imparity in data availability and quality across states and over time contributes to reducing availability heuristic and can aid regulators and stakeholders in identifying best practices.

Wellbore-level data typically does not contain information related to design elements, mechanical integrity testing, or other information necessary for a rigorous assessment of well integrity, therefore the inability to test certain assumptions remains a key limitation of this study. Given this lack of data, we developed an indicator method designed to evaluate the presence of previously identified well design deficiencies that can contribute to containment loss, using data that is consistently available on a nationwide basis. There is a potential for misclassification in identifying well design deficiencies such as SPF, however most of the assumptions in our methodology are likely conservative (see SI table 2). We relied on findings and recommendations by the ITF report on Natural Gas Storage Safety, the IFR, and the recent regulatory amendments applying to California's UGS wells.

This assessment of UGS well deficiencies is limited in scope to original well design elements such as wells not designed for UGS and wells exhibiting limited passive barrier protections. The focus on wellbore integrity assessed here is in agreement with previous studies [11–15, 29]. Our attempt to identify initial well design and SPF designs are supported by previous studies [23, 30], the Interagency Task Force on Natural Gas Storage Safety [3], and the recent regulatory amendments applying to California's UGS wells [21]. The pre-1979 well construction date as a proxy for single barrier design is supported by limited studies of well- and barrier-failures in certain locations [3, 23, 30]. Kell [30] showed that Ohio wells constructed prior to 1983 were more than twice as likely to leak (0.1%) compared to post-1983 wells with a failure rate of 0.035%. Similarly, in Texas, wells constructed before 1983 were five times more likely to leak (~0.02%) than wells constructed after 1983 (~0.004%) [30]. Though age alone does not pose a hazard if integrity is managed, further information on UGS well-level incidents is needed to assess UGS well age as a causal factor.

Our dataset contains nearly 5000 more active UGS wells than cited in the ITF report [3]. The source of this discrepancy is unclear, and is particularly apparent for OH, MI, WV, PA, and IA. Further, the methodology applied here likely underestimates the total number of active UGS wells because our estimate excludes: (1) wells with an unknown status that join to active storage fields; (2) wells not coded as 'storage' that may also be connected to storage formations (e.g. production/withdrawal only); and, (3) full storage-related well data from AK, TX, OK, and TN. Likewise, both the number of repurposed wells and the number of wells that that exhibit single barriers are likely underestimated due to the potenital misinterpretation of completion date proxying for original well construction. Additionally, explicit well function was available for only 6483 active UGS wells limiting our ability to distinguish between active injection and monitoring wells that may explain a portion of the count discrepancy.

Studies are in progress to evaluate various aspects of the natural gas midstream infrastructure [31] and

improve existing emissions estimates and source apportionment for natural gas production and storage activities [32]. While greater precision has been achieved in attributing atmospheric methane to oil and gas emissions and fugitive leaks [33–36], the GHGI can be further improved by refining infrastructure and activity data from this sector [37]. This UGS database with identified uncertainties can improve characterization of both UGS field and well activity. With potential secondary and tertiary uses of subsurface reservoirs likely to increase in the future, data and results presented herein can inform hazard identification and risk assessments for geologic storage of CO_2, underground fluid disposal, and compressed air storage [17].

Conclusion

The natural gas leak at the Aliso Canyon facility highlights the immense hazard potential that a single UGS well can possess. We identified 2715 active UGS wells across the US that, like the failed well at Aliso Canyon, were not originally designed for gas storage. The 99% of repurposed wells constructed prior to 1979 are particularly likely to exhibit certain design deficiencies including single passive barrier protection. An estimated 210 active repurposed wells were constructed before 1917—before cement zonal isolation methods were utilized. These wells are located in PA, OH, NY, and WV and represent the highest priority related to potential design deficiencies that could lead to containment loss.

Acknowledgments

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Ex. I - 8

UNDERGROUND NATURAL GAS STORAGE

INTEGRITY & SAFE OPERATIONS

energy API INGAA AGA American Gas Association

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Underground Natural Gas Storage

Integrity and Safe Operations

Prepared by:

The American Petroleum Institute

The American Gas Association

The Interstate Natural Gas Association of America

Find the full report here:
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July 6, 2016

Introduction

The recent natural gas leak from the Aliso Canyon facility in California has prompted federal and state regulators to reexamine the regulation of underground natural gas storage facilities. The intent of this paper is to enhance the technical understanding and to provide context around the implementation of the recently developed American Petroleum Institute (API) recommended practices addressing the safe operations of underground natural gas storage facilities –API Recommended Practice 1170, Design and Operation of Solution-mined Salt Caverns Used for Natural Gas Storage, (API 1170) and API Recommended Practice 1171, Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs, (API 1171). These standards were developed by a group of technical experts from industry and government and were published by API in 2015. They cover the design and operation of salt cavern storage and the design, construction, operation, monitoring and maintenance of depleted hydrocarbon and aquifer reservoirs.

The Aliso Canyon incident also focused the spotlight on the application of Emergency Shutdown Valve (ESV) systems as a tool for consequence mitigation of events that may occur downstream of the valve. This paper includes an appendix that provides a comprehensive review of ESV systems, including their operation, application, benefits, and reliability challenges. This appendix is intended to advance the technical understanding of ESVs and to provide context around ESV implementation.

Underground storage of natural gas is an integral component of the nation's energy system. Our nation's significant storage capacity – nearly four trillion cubic feet – enables utilities to offer clean natural gas to consumers throughout the year with reliable service and prices. Natural gas storage enables companies to adjust for daily and seasonal fluctuations in demand throughout the year while natural gas production remains relatively constant year-round. Without storage, customers, including power generators, transportation operators, and residential users, would be faced with potential supply shortages and highly variable prices.

Natural gas storage operators have consistently provided safe and reliable natural gas storage. Because of the critical importance storage plays in the nation's energy portfolio, natural gas storage operators are continually searching for new equipment, processes, and methodologies to improve safety and reliability.

This paper is the product of a collaborative effort between members of the American Gas Association (AGA), the American Petroleum Institute (API), and the Interstate Natural Gas Association of America (INGAA). Portions of this paper advocate that federal and state regulators take certain regulatory actions and refrain from taking other regulatory actions.

The information included in this paper represents the industry's best practices and decades of expertise in developing and operating natural gas storage facilities. The goal of this paper is to provide information that is instructive and helpful for regulators responsible for ensuring the continued safe and reliable delivery of natural gas for their constituents.

Executive Summary

Natural gas storage operators have recognized a need to generate a standardized set of recommended practices to provide guidance in the areas of risk and integrity management for natural gas storage wells and reservoirs. A fundamental goal of natural gas storage management is containment of the stored gas within the facility. A team that included federal and state regulators along with natural gas storage operators developed American Petroleum Institute (API) Recommended Practice 1171, Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs (API 1171) to address the need for consistency among the industry. In September 2015, following a three-year development effort, API 1171 was published. API 1171 brings together a variety of leading industry practices for design and operations of natural gas storage facilities with risk management providing the basis. Following the release of API 1171 and PHMSA's reference to the standard in a February 2016 advisory bulletin, operators have been conducting gap analysis to compare the new standard to their own integrity management practices.

The risk-based approach to well integrity management advocated in API 1171 includes five steps: 1) Data Collection, Documentation and Review, 2) Hazard and Threat Identification, 3) Risk Assessment, 4) Risk Treatment – Developing Preventive and Mitigative Measures, and 5) Periodic Review and Reassessment. Lessons learned from historical gas storage events resulting in loss of storage containment had a role in shaping API 1171. A 2013 literature search and informal industry survey of historical natural gas storage incidents in the U.S. showed on average one major storage incident occurring per decade and less severe events occurring intermittently. While this indicates the likelihood of a major incident occurring is very low, the objective of API 1171 is to further drive down any potential risks. Recognizing that well integrity data verification and assessment must be done for every storage well in order to effectively apply the management practices in API 1171, operators are working towards uniform application of the standard.

Storage well integrity management programs are developed with a life cycle approach that includes well design, construction, commissioning, operations, maintenance, and abandonment using effective procedures, training, documentation and records retention and relying on the knowledge, skills, and experience of the personnel and the organization managing the facility. Design factors employ one or more barriers such as casing, the wellhead, and cement, to provide containment of storage gas. Specific designs using equipment, such as emergency shutdown valve systems or tubing and packer well configurations, must be evaluated using the risk management process as these designs add potential risk and no single specific approach provides a panacea to mitigate all potential integrity issues. New and existing designs can both be successfully employed within a risk-based integrity management program. Risk assessments are used as a basis for developing the integrity demonstration, verification, and monitoring tasks and for evaluating their frequency requirements. The operator's approach addresses the need for re-evaluation of risk-based conclusions, and the frequency of monitoring tasks. These monitoring tasks and other operating practices are performed by trained personnel and require documentation and continual improvement processes as part of storage integrity management.

Operators have projected full conformance with API 1171 following a final rulemaking could take 7-10 years, taking into account the gap analysis currently underway to compare the new API 1171 to individual integrity management practices, and the development and implementation of risk assessment techniques applicable to an operator's specific storage fields, integrity management plans, inspection

and maintenance practices, emergency management plans and storage well blowout contingency plans, and procedures for well and reservoir integrity tasks and activities (management of change, training and competency programs).

Overview

The underground storage of natural gas is a critical component of the natural gas supply system in the United States. On the highest demand days, storage delivers about half of the natural gas consumed. As natural gas becomes an increasing part of our national power generation and energy portfolio, these storage assets will continue to play an important role. Approximately 400 gas storage facilities, comprised of almost 17,500 storage wells provide service today. Eighty percent of storage facilities employ geologic formations, or reservoirs, that originally contained natural gas and/or oil reserves and were converted to depleted reservoir storage. The remaining facilities are engineered for gas storage using either deep, water-filled geologic formations, aquifers, or caverns that have been created in salt formations using a solution mining process[1]. This paper focuses on natural gas storage well integrity in depleted reservoir and aquifer facilities and provides an in-depth discussion of Emergency Shutdown Valve systems in onshore, natural gas storage wells.

The overall objective of a storage facility integrity program is to help ensure and confirm that storage gas is confined in the system. A storage facility can be divided into four distinctive physical components: the reservoir, the well(s), the storage pipeline system and the compressor station. The latter two are regulated by the U.S. Department of Transportation (DOT) under 49 C.F.R. Part 191 and 192 and are not within the scope of this paper. The first two physical components of a gas storage facility are addressed in American Petroleum Institute (API) Recommended Practice 1171, "Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs" (API 1171). API 1171, which was published in September 2015, represents a three-year effort by a working group including representatives from DOT's Pipeline & Hazardous Materials Safety Administration (PHMSA), the Federal Energy Regulatory Commission (FERC), state regulators, and industry to develop natural gas storage well and reservoir integrity standards that combine consensus best practices, regulations, and concepts adapted from risk management and safety management systems.

This paper further describes natural gas storage well integrity. Natural gas storage well integrity management programs are developed with a life cycle approach that includes well design, construction, commissioning, operations, maintenance, and abandonment using effective procedures, training, documentation and records retention and relying on the knowledge, skills, and experience of the personnel and the organization managing the facility. Safety and integrity of storage wells are managed using a risk informed approach that includes identifying threats and hazards at each site, analyzing and evaluating the risk, and developing preventive and mitigative programs to manage the risk[2].

As part of the continual improvement process described in API 1171, this paper describes processes in place or under development by operators. API 1171 was finalized in September of 2015 and the industry is in a foundational state developing conformance with API 1171. Operators are at various stages in their efforts to enhance their existing integrity management processes to achieve conformance with the

[1] Additional background information on natural gas storage in the United States is provided in Appendix 1 via a brochure, "Supporting the American Way of Life- The Importance of Natural Gas Storage", developed as a joint effort of the American Petroleum Institute (API), the Interstate Natural Gas Association of America (INGAA), and the American Gas Association (AGA).
[2] Section 8 of RP1171 describes the risk management approach for storage wells and reservoirs.

robust consensus standards established in API 1171. These efforts begin with a gap analysis to compare the new API 1171 to the operator's individual integrity management practices, and then move to the development and implementation of risk assessment techniques applicable to an operator's storage fields, integrity management plans, inspection and maintenance practices, emergency management plans and specific storage well blowout contingency plans, and procedures for well and reservoir integrity tasks and activities (management of change, training and competency programs). Operators as referenced in this paper are seeking to conform to API 1171 and have estimated that conformance can be achieved within seven to ten years of a final rulemaking.

The following discussion is organized into four sections beginning with a description of the storage well integrity management process and its strong relationship to risk management process. Lessons learned from historical storage well gas release events are reviewed in the second section. An examination of storage well integrity design factors is contained within the third section. The final section reviews operational approaches to managing storage well integrity.

1. Natural Gas Storage Well Integrity Management Process & Risk-Based Approach (API 1171 Section 8)

The natural gas storage well integrity management process starts with a comprehensive risk assessment. The assessment includes data collection, hazard and threat identification, likelihood of occurrence estimation, and consequence severity determination. Preventive, mitigative and monitoring practices are developed that can reduce the potential for an integrity compromising event. Periodic review and reevaluation of the risk assessment and the effectiveness of the safety management program complete the process[3].

The risk management program discussed below and incorporated in API 1171 has three fundamental components - physical plant design, processes and human factors. The physical plant includes design features with the ability to contain pressurized storage gas. The process component includes the technical and procedural systems that promote the identification and mitigation of threats while also identifying and managing the consequences in the design, construction, commissioning, operations and abandonment phases of a storage well life cycle. The processes also include audit procedures, emergency response plans and a continual improvement cycle. Neither the physical plant nor the processes would be totally effective without effective management of human factors. Operators develop staff knowledge, skills and abilities to safely and efficiently manage their responsibilities for storage well integrity. A management team that fosters a robust health and safety culture is important to the success of human factor management. Ineffectiveness or failure in any one of these three components can lead to loss and/or escalation of a minor event into a potentially major incident.

The operator's risk assessment must take a holistic approach to storage well and field integrity to effectively manage risk. It should be noted that while this paper is focused on addressing the integrity of storage wells, some of the threats and preventive and mitigative measures pertain to both the storage wells and the storage reservoir. An example would be third party damage, such as vehicular

[3] Appendix 2 is a flow chart from RP1171 presenting the various steps for well and reservoir integrity management.

impact to a wellhead (well risk) or a third party oil and gas producer drilling through the storage reservoir to a deeper formation (reservoir risk).

Step 1- Data Collection, Documentation and Review (API 1171 Section 8.3)

Good practices in well integrity management involve the collection and maintenance of information for each storage well for the life of the facility. Importance is placed on understanding how the well was originally drilled, configured, and completed; the purpose of subsequent reconditioning work and other maintenance activities; the characteristics of the geologic environment encountered by the well; reservoir and injected fluid properties; well performance capability; and wellsite information. Operators integrate these data to develop a holistic understanding of the threats and hazards presented to each storage well and to the entire storage facility.

Types of data collected include geologic information on the formations penetrated by the storage well, wellbore configuration and completion data (e.g. casing characteristics, setting depths, cement, etc.), pressure and volume data on the flow capability of the well, annular pressure and/or volume data, reservoir fluid analysis, wellhead design, and other characteristics of the subsurface in addition to information about the wellsite. Sources of data include storage operator records, third party records, and information filed with the state geologic survey and/or oil and gas regulatory agencies.

Step 2- Hazard and Threat Identification (API 1171 Section 8.4)

A hazard is a potential situation or condition that could cause the loss of or damage to a natural gas storage well. A threat can be caused by activation of a hazard. Note that due to the variety of well designs and the diverse geologic and geographic settings of wells, hazards and threats vary from one storage well to another as well as from one facility to another.

Appendix 3 includes a detailed listing of common threats and hazards to storage wells. This list was developed for API 1171 and included input from operators representing the majority of storage wells in the United States with hundreds of thousands of well-years of operational experience. API 1171 encourages operators to utilize the list and supplement it as necessary based on well-by-well, site specific assessments. Operators are also encouraged to consider the potential for interactions between specific threats and/or hazards. A lack of data is not used as justification to exclude a specific threat.

An individual storage well has one or more design features to contain the storage gas inside the wellbore and in the storage reservoir. Physical components of a well that act as barriers to the gas and protect against potential loss of containment events are the casing in the well and cement behind that pipe. Potential consequences from the failure of containment include storage gas escaping to freshwater formations or to the surface at or near the wellhead. In addition to those downhole features, the wellhead is designed to control the flow of gas from the wellbore to the pipeline system. The wellhead design can also provide access to the annulus to identify potential loss of containment from the production casing. Redundant or multiple barriers can promote higher reliability as a second barrier, such as cement behind the production casing can contain the gas if the first barrier fails. Storage operators can monitor parameters such as operating pressure, temperature and flow conditions to confirm normal operating conditions and limits and to detect abnormal conditions. Assessing the risk presented by an individual well, therefore, incorporates both the type and the quality of design features

that exist, in addition to the operator's procedures and personnel training. Some causes of the loss of containment of storage gas, based on operational experience, are discussed later in this paper.

Operators will periodically review the threats and hazards for each well to account for changes in perception of likelihood or consequence of event occurring. This review also provides the most up to date information for the risk assessment. As an example, operators will review events in the storage industry and evaluate the risk of a similar event occurring with their storage wells.

Step 3- Risk Assessment (API 1171 Section 8.5)

The operator's risk assessment uses tools and techniques that evaluate and prioritize risks so as to direct risk management activities toward promoting the functional integrity of the storage wells.

The risk assessment method includes:

1. Identification of potential threats and hazards to a given storage well,
2. Evaluation of the likelihood of events and consequences,
3. Risk ranking to develop preventive and mitigative (P&M) measures to monitor and/or reduce risk,
4. Documentation of risk evaluation and decision basis for P&M measures,
5. Provision for data feedback and validation, and,
6. A continual improvement cycle by way of periodic risk assessment reviews with updated information so as to evaluate the risk management effectiveness, and to modify/update the potential threats and hazards and P&M measures needed to address these threats and hazards.

Step 4- Risk Treatment- Developing Preventive and Mitigative Measures (API 1171 Section 8.6)

Risks to a specific storage well can be effectively managed with P&M measures which reduce the likelihood (preventive), reduce the consequence (mitigative), or by a combination of both. Appendix 4 contains a table adapted from API 1171 listing the common P&M measures for different threats or hazards. This list was collaboratively developed by operators owning the majority of storage wells in the United States and represents hundreds of thousands of well-years of experience in managing well integrity risks. The list also incorporates efforts by operators to develop new technology and represents the currently available tools, techniques and practices for storage well integrity management. Operators will continue to support new technological developments pertaining to well and reservoir integrity.

Operators are using the P&M measures identified in API 1171 to determine the applicability of each P&M measure to their wells and are supplementing the list as necessary for site specific conditions. Operators will then employ applicable API 1171 P&M measures and train their personnel on the procedures related to those measures.

Step 5- Periodic Review and Reassessment (API 1171 Section 8.7)

Storage wells can be in operation for many years and while the passage of time itself does not pose an additional threat if facility integrity is managed, the threats to each storage well can and likely will change over time. Examples include surface encroachments on well sites due to farm land being converted into housing developments or the discovery of new productive oil and gas formations below

the storage reservoir leading to third party drill activity through or in proximity of the storage formation. Therefore, operators periodically review the integrity management programs and risk assessments to update identified potential threats and to evaluate utilization of P&M measures to address the risk. The review interval is short enough so that the data and information brought into the analysis are meaningful. Operators conduct their risk management as an ongoing activity.

Operators also maintain a continual improvement cycle for risk management activities that incorporates new procedures, practices and technology when relevant to a specific storage facility. Experience has shown that significant technological advancements can occur over the long life of a storage well. Operators stay abreast of these developments and incorporate new technology and best practices as appropriate.

2. Lessons Learned from Historical Underground Natural Gas Reservoir Storage Well Events (API 1171 Sections 8.4 and 8.7)

Unplanned releases of natural gas from underground storage wells, while rare, have occurred. A literature search of historical release events was conducted in 2013 to better inform the API 1171 development team. The information compiled came from publically available sources and an informal survey of underground storage operators. The informal industry survey covered nearly 14,000 wells contained in 226 fields, and represents a sampling of over 80 percent of the natural gas storage wells in the United States. The publically available information came from newspapers, Geologic Survey reports, state oil and gas inspector notes and other available public information. These statistics exclude the Aliso Canyon incident, which commenced October 2015, after API 1171 was published.

A process safety tier ranking system referenced from API RP754, "Process Safety Indicators for the Refining and Petrochemical Industries" second edition, April 2016, (RP754), can be used to categorize the incidents from the informal industry survey and publicly available information review referenced above. Although RP754 is written for the refining and petrochemical industries, the application of the tier structure has merit since the storage incidents referenced herein represent loss of product containment. Tiers 1 and 2 are lagging indicators and are suitable for nationwide public reporting. Tiers 3 (challenges to safety systems) and 4 (operating discipline and management system performance) are leading indicators used by companies for their internal review and improvement.

As defined in RP754, Tier 1 Process Safety Events are more significant incidents that result in the unplanned loss of containment and one or more of the following consequences:

- An employee, contractor, or subcontractor "days away from work" injury and/or fatality;
- A hospital admission and/or fatality of a third-party;
- An officially declared community evacuation or community shelter-in-place including precautionary community evacuation or community shelter-in-place;
- Fire or explosion damage resulting in greater than or equal to $100,000 [4]of direct cost.

Tier 2 Process Safety Events are unplanned loss of containment events with a lesser consequence than Tier 1 that result in one or more of the following consequences:

[4] This reporting threshold is referenced from API754, Part 191's incident reporting (191.3) threshold is $50,000 in damage, which is a subset of direct cost. The authors are not suggesting modification to the reporting definitions in 191.3.

- An employee, contractor or subcontractor recordable injury;
- Fire or explosion damage resulting in greater than or equal to $2,500 of direct cost.

The data search for unplanned storage well releases identified 61 events between 1953 and 2010. A breakdown of the incidents by decade along with an application of the RP754 Tier 1 and 2 structure (the severity of the incident) is shown in Table 1.

Decade	Number of Incidents	Injuries	Fatalities	Tier 1 Incident	Tier 2 Incident
1950-1959	2	0	0	0	1
1960-1969	10	7	4	1	4
1970-1979	15	3	0	2	9
1980-1989	7	0	0	0	3
1990-1999	18	5	0	1	8
2000-2010	9	0	0	0	5

Table 1 – Storage Well Incidents by Decade

It is worth noting that the largest number of injuries and fatalities is attributed to a single incident in 1969. The two Tier 1 incidents in the 1970's were related to two separate well fire incidents resulting in burns to workers. After the 1970s, there was one Tier 1 incident in 1997 that was due to the overpressure of a brass valve which blew apart and injured two workers.

Based on the event data reported since 1990, and taking into account the Aliso Canyon incident, the likelihood of an event occurrence, calculated using the Center for Chemical Process Safety [5] (CCPS) American calculation for hazardous process facilities, results in a "very unlikely" to "extremely unlikely" or "remote" classification. Implementation of API 1171 is expected to reduce this likelihood further.

Table 2 furthers the analysis by organizing the events according to the threat categories as shown.

Threat	Occurrences
Well Interventions	20
Wellbore Leak	22
Third Party/Outside Forces	6
Design	7
Wellhead/Gathering	5
Unknown	1

Table 2 – Storage Well Threats and Occurrences

This analysis shows about 30 percent of the events occurred as a result of well interventions (i.e., activities associated with the operator entering the well for some type of remedial, valve maintenance, or other work) and another 30 percent were caused by issues with the downhole tubulars. Of the

[5] (CCPS) American Institute of Chemical Engineers (AIChE); CCPS order of magnitude event frequencies align to qualitative descriptors: "extremely unlikely to remote" is <1E-05, "very unlikely" is in a range of 1E-05 to 0.99E-03

reported wellbore leaks due to issues with downhole tubulars, 12 were of undocumented origin, four were due to casing corrosion, four due to mechanical issues, and two were the result of manufacturing defects.

Fifty-one of the reported events included an estimate of the length of time for the event to be resolved. Eleven incidents took longer than a month to contain and seventeen were resolved in less than 30 days. Twenty-three events were contained within two days with most of these contained in less than 24 hours.

Of the 61 events identified in this review, one, in 1969, resulted in seven injuries and four fatalities to the public. In 21 events, the general public was impacted through road closures, water supply replacements, building damage and evacuation of homes.

It is recognized that the frequency of Tier 1 and 2 incidents has remained flat over time. Operators continually learn from historical events which, among other things, prompted the development and use of improved casing inspection tools.

Operators currently employ a variety of methodologies to ensure the functional integrity of the storage wells they operate. The storage facilities are designed to operate within maximum operating pressure limits of the reservoir and all connecting elements from the well, wellhead assembly, and the connected pipeline system and any ancillary equipment. The development of API 1171 represents a significant effort to improve upon the process safety record through the use of a standardized risk-based approach to natural gas storage integrity.

3. Storage Well Design Factors (API 1171 Sections 6.2)

A. Wellhead Equipment (API 1171 Sections 6.2.1, 6.2.2, 6.2.3)

All wells include a system of surface-mounted valves to control flow, commonly referred to as the wellhead. Wellhead configurations have proven to be effective barriers to control flow of stored natural gas. The underground storage of natural gas began in the United States one hundred years ago. Originally, many surface-mounted valve assemblies were referred to as production style and were often fabricated in the field by welding pipeline components and valves to the well itself. Over time operators have replaced the design of the original well control configurations with more standard and conformance tested equipment. Today, the wellhead equipment used for new underground natural gas storage wells consists of equipment that conforms to API Specification 6A standards. The wellhead equipment is composed of a number of valves and components that isolate the well casings within the wellhead assembly and provide control of the well at the surface. This control allows the well to be open to or shut from the pipeline system and provides for the connection of equipment for any potential future remedial well operations. Ports on the wellhead assembly allow for the measuring and monitoring of pressures and flows from the different casings, including the flow string itself and annular space between the casings. These API 6A standard wellheads contain a master valve that allows for full diameter access to the production casing for future inspections of the well casings.

Other factors included in the specifications of the wellhead and related equipment include the expected flow rates and flow paths, potential future increases in operating pressures, any anticipated treating or

stimulation pressures, chemical composition of fluids injected and withdrawn (including those used for treating or stimulation) and servicing and maintenance needs for the wellhead as identified by the original equipment manufacturer. In designing the well, wellhead, and related equipment, operators also evaluate the future inspection, servicing, and maintenance needs for the well. Included in this evaluation are valve type and sizing factors to allow for mechanical inspection of the wellbores.

Another aspect of well design is an evaluation of the corrosive potential of any formation fluids that may enter the well or annular space of the well along with decisions made whether or not to induce current on the well casing as part of a cathodic protection system. In addition, the assessment of erosive impact of formation particulates or stimulation treatment materials is included with the well component design.

B. Well Configurations (API 1171 Section 6.3)

As with storage wellhead assemblies, storage wells have existed for many decades in various configurations. The storage well provides isolation from groundwater, controls wellbore conditions, isolates the storage gas within the storage reservoir and allows for injection into the reservoir or withdrawal from the reservoir.

Operators refer to API TR 5C3, which provides technical details regarding the strength of casing and tubing, to design casing configurations for their wells. Typically the oil and gas regulations within a given state prescribe the minimum requirements for well completions. The API published burst values in the 5C3 bulletin include a built-in 12.5 percent safety factor to allow for the manufacturing tolerance of the pipe wall. These published burst values are used by operators to confirm that their well completions can withstand the maximum anticipated operating pressures and temperatures of their wells. In many cases, storage operators construct storage wells with casings rated for significantly greater pressure containment than the pressures expected for normal operations of the storage well. Operators utilize commonly available casings, which may have higher pressure ratings than minimally required, simply because of their availability. Some operators may stimulate wells at higher pressure in the future and factor this plan into the original casing design. Operators will verify casing capability to withstand stimulation pressures prior to stimulation. In any case, operators verify that the ratings of the casings installed in the well exceed the anticipated pressure containment needs.

Storage wells extend from a few hundred feet to several thousands of feet beneath the surface. The wells connect the underground reservoir rock, where gas is stored in the porous and permeable rock formations, to the surface wellhead assembly, the system of valves and components that connect the well to the pipeline system.

Storage wells are constructed in a concentric manner with larger diameter casing installed nearest the surface and smaller diameter pipe extending from inside to deeper underground formations. The casing is composed of sections of pipe known as joints that are about 30 - 40 feet long and form the casing string that connects the reservoir to the wellhead. The joints are typically screwed together with engineered connection collars that include thread compound to assist in providing a seal for each joint, ultimately forming a continuous barrier along the entire casing string. This casing string confines the stored natural gas inside the pipe and also acts to prevent any external substances from entering the well.

As specified in API 1171, a new storage well contains at minimum two casings; the surface casing and the production casing. Cementing these casing strings, in part or wholly to the surface, provides an additional zonal isolation barrier by sealing the void space between casing strings and/or between casing and the rock formations. This system provides isolation of the stored natural gas from the surrounding rock formations, allowing the production casing to contain the flow of gas in and out of the storage reservoir. The casing and cement well barrier elements [barriers] provide the foundation for managing well integrity.

The following describes an example storage well configuration:

- Conductor casing: the conductor casing is the widest diameter pipe used in the well and is of sufficient size and strength to control the near-surface movement of earth and provide stability for future drilling operations. This pipe can be cemented in place by grouting to the surface and is not connected to the wellhead.
- Surface casing: the surface casing's main purpose is to isolate the well from sources of fresh water and to provide additional stability for deeper drilling of the well. This pipe is typically screwed together and usually cemented in place from the bottom to the surface by displacement.
- Intermediate casing: in some cases, a well may contain an intermediate casing string to isolate the well from coal, salt, other mineral deposits, and/or gas bearing zones, to control subsurface conditions and to provide additional stability for deeper drilling of the well. This pipe is typically screwed together and often cemented in place from the bottom to the surface by displacement.
- Production casing: Inside these other casings is the production string which provides access to the storage reservoir formation itself. This string provides isolation of the natural gas that is being stored. Typically, production casing is screwed together and cemented in place from the formation, either to the surface, to a level above the storage formation deemed adequate for containment, or to the casing set point of an intermediate or surface string by displacement. The casing is thus sealed in place and prevents any flow of gas or other fluids in the annular space between the pipe and the surrounding rock formation.
- Production tubing: In some cases, a smaller diameter string of pipe known as tubing, which like the casing is normally threaded pipe joined by engineered connections, is installed inside the production casing. Gas can be injected or withdrawn through the tubing, the tubing/production casing annulus or both depending on the well configuration. If tubing is used, the velocity of flow is greater due to the reduced cross sectional area of the tubing as compared to the casing, and liquids can be lifted from the bottom of the well to the surface. In this case, tubing is not cemented in place, but hangs from the surface wellhead assembly or is set on a packer which has anchoring slips and a rubber packing element that seals the space between the tubing and production casing. Tubing set on a packer seals the storage formation pressure and fluids from the production casing. The annular space between the tubing and production casing can be filled with fluid and inhibitors to protect against corrosion. If an operator drills and completes a new well with a tubing on packer completion, and the well requires high deliverability to meet design flows, the casing design results in larger diameter

pipe than would be the case for a well with similar deliverability completed without tubing. However, retro-fitting wells with tubing on packer completions results in a detrimental effect on service reliability, on peak deliverability and potentially to seasonal working gas capacity, as the cross-sectional area available for flow is reduced. An operator could drill substantially more wells to make up for the loss in order to maintain deliverability and turnover requirements. Since additional wells would be required, the overall risk impact with the storage field could be increased. An operator's site-specific risk assessment provides guidance for a decision on casing/tubing requirements for the design of new wells and the applicability for existing well completions.

C. Zonal Isolation (API 1171 Section 6.2, 6.3, 6,4)

The storage well casing, cement and wellhead assembly provide the zonal isolation, or barrier envelope, for a well. These barriers are designed to withstand the maximum operating pressures, including stimulation or treatment pressures, temperatures, flow rates, flow compositions and provide the necessary isolation of the stored natural gas from the well's surrounding environment. The well casing and wellhead assembly are confirmed to have mechanical integrity through testing and maintenance. In addition to API 1171, ISO Technical Specification document 16530-2 "Part 2: Well Integrity for the Operational Phase" includes a section defining well barriers in more detail. See Appendix 5 for examples of gas storage well configurations. Example A depicts a well showing a wellhead assembly on the surface connected to the storage zone through the production casing inside surface and conductor casings with cement sealing the annular spaces between formation and pipe and between the different casings. Example B depicts a well showing a wellhead assembly on the surface connected to the storage zone through both production casing and tubing inside surface and conductor casing. Cement is shown in Example A between the production casing and formation and between the casings. The tubing is not cemented in place and may or may not contain a packer element at the bottom to seal the annular space between tubing and casing. Without a packer, flow could occur through the tubing and/or the tubing/casing annulus; however, with a packer flow could only occur through the tubing.

On the surface, the wellhead assembly contains a master valve that provides isolation of the well from the atmosphere and the pipeline connection. The operator in some cases may decide to install tubing in a well that can either be used as a velocity string to help remove fluids or set on a packer to provide a seal for the annular space between the tubing and production casing. Additional barriers are the seals within the wellhead itself and other valves on the wellhead assembly.

The operator evaluates the entirety of the barrier envelope when making decisions regarding the inclusion of an emergency shutdown valve (ESV). A variety of criteria, as more fully described in Appendix 6, are evaluated in determining the need for an ESV in any particular well. These factors include, but are not limited to, the flow potential and flow composition and the proximity relationship to dwellings or human congregation areas, the accessibility of the well for emergency response including the proximity of the well to other wells or structures, the proximity to vehicular, air or rail traffic and industrial sites, the added protection of other barrier options, and the risks of installing and servicing the ESV itself.

Each of the above barriers is a component of protection to maintain the isolation of the stored gas in the well and to prevent any contamination from entering the well itself from the surrounding rock formations. Storage operators design the well completions to provide zonal isolation that meets or exceeds regulatory requirements of individual state oil and gas agencies.

D. Cementing Practices (API 1171 Section 6.4)

In addition to the casing in the well, the purpose of cementing is to provide a seal, or zonal isolation, primarily by preventing movement of gas or other fluids vertically behind the casing, which is an important part in maintaining well integrity. Over time, installing a seal around casing has evolved from some instances where operators placed a gelled fluid or drilling mud into the annular space between casings or casing and the rock formation to a more refined and specific process. Today, cementing is the process of mixing a slurry of cement, water and cement additives and placing it in the well by pumping it through the casing to fill the annular space between the casing and formation or previous string of casing. Once the cement has cured to sufficient compressive strength, the cement provides support to the casing, and bonds the casing to the formation for zonal isolation. Cement provides an additional barrier element and can also protect the casing from external corrosion. Cement used in well construction meets or exceeds the requirements of API Specification 10A or ASTM C 150/C 150M Standard Specification. These specifications list chemical and physical properties for different classes of cements.

E. Cement Design (API 1171 Section 6.4.4)

Placement of cement so that it completely surrounds the casing and removes all drilling mud from the annulus is important to a successful cement job. Operators face numerous challenges with cementing casing that affect the placement of cement behind the casing. Drilling fluid and borehole quality can affect both the running of casing and the displacement of the drilling fluid during cementing operations. The stability of the borehole could be compromised due to sensitivity with the cementing materials and related fluids chemistry which may lead to caving and the inability to circulate and effectively place the cement. All of these challenges are factored into the risk assessment for the well and incorporated into the cement design.

Operators use casing hardware to assist in centralizing the casing and placing uncontaminated cement around the casing. A casing shoe, which helps guide the casing through the wellbore to bottom and protects the bottom of the casing from damage, is run on the bottom of the casing. Centralizers are used in an effort to offset the casing from the borehole wall, since it is difficult to remove drilling fluid and place cement in areas where the casing is too close to the borehole wall. Float equipment is used to restrict back flow into the casing after cementing and prevent cement contamination near the shoe of the casing. Wiper plugs provide separation between the cement slurry and drilling fluids, wipe the inside of the casing of drilling fluids and cement and provide an indication of the end of displacement of the cement slurry.

Slurry design takes into account the amount of cement needed for zonal isolation and the cement top location. Pore pressures and fracture gradients are also evaluated in the slurry design. Inadequate formation competence could lead to an inability to support hydrostatic pressures of columns of cement

slurries, leading to formation breakdown, loss of cement column and the inability to place the cement as desired. Cementing back to the surface from total depth can provide additional barriers, annular isolation and additional burst protection over and above burst strength of the casing. In deeper wells, high downhole pressures due to the hydrostatic weight of the cement slurries, combined with additional friction pressures of the viscous slurries, can lead to lost circulation or inadequate annular fill. Operators can use mixed density cements, pumping a lighter weight lead cement that reduces the hydrostatic weight of the full cement column in the well, to mitigate potential lost circulation or inadequate fill. Operators may also use stage tools in the cementing design that allow sections of the well to be cemented at separate times or in stages to reduce the hydraulic head. The operator's risk assessment for the well helps them determine the best method to use in the cement design for a specific well.

Pre-flushes, high annular velocities, high slurry densities and pipe movement are other techniques that operators apply to aid in effectively removing the drilling fluid from the hole during cementing. Pre-flushes help to avoid incompatible fluid interactions with drilling mud and cement. High annular velocities with high slurry densities provide more energy to remove gelled drilling fluids and pipe movement aids in coating the cement slurry on all sides of the pipe. API 65-2 "Isolating Potential Flow Zones During Well Construction," Section 5, "Cementing Practices and Factors Affecting Cementing Success", discusses in more detail many of the areas that operators address for placement of the cement. Competent cement is an important component of the barriers that can contain storage gas if the production casing develops an integrity issue.

When zonal isolation is not achieved or the casing is compromised during the cementing process, operators utilize remedial techniques to repair the wells and provide isolation. For wells with cement to the surface, remedial techniques may include internal patches to repair casing defects or squeeze cementing to improve zonal isolation. Operators evaluate the remediation required along with any associated risks in determining the correct actions to take to repair a well. Those risks can include reduced internal diameter of the casing below the point of remediation and creation of new potential leak paths.

F. Cement Evaluation (API 1171 Section 6.4.6)

Operators use cement evaluation techniques to determine the placement and quality of the cement in a well. For a new or reconditioned storage well, API 1171 requires operators to use a cement bond log (CBL) or other means to determine the placement and bond, or sealing quality, of the cement. API TR 10TR1 reviews various types of cement evaluation logs that operators use, including the CBL, and their features and limitations. New well construction designs should include running the CBL log during the completion process while the wellbore is still full of drilling or circulating fluid. Existing wells can also be evaluated with CBL tools. The historic sonic-based CBL technology requires a liquid-filled wellbore to enable the tool to perform properly. Filling the wellbore with fluid includes added risks, from the introduction of fluid to the well, removing the fluid from the wellbore and possible corrosion from residual fluid left in the wellbore. Operators evaluate risks prior to any well intervention and incorporate these prior to running the CBL. New CBL technology, currently in the field testing mode, does not require a fluid-filled wellbore and, once validation is confirmed, may be a promising alternative for certain aspects of casing-to-cement evaluation. This new tool does not currently evaluate the cement-to-formation bonding, which the older CBL technology may provide.

G. Well Closure (Abandonment) (API 1171 Section 6.7)

A storage operator may choose to permanently close a storage well. This closure is referred to as plugging and abandoning the well. Once this decision is made, the operator designs a well closure plan to isolate the well from the storage zone and any other strata that the well penetrates. This closure of the well removes the well as a conduit for the flow of fluid between different zones penetrated by the well or from one of these zones through the well to the surface. State oil and gas regulations often specify the requirements for well closure operations.

Cement plugs, mechanical plugs or a combination of both are used to isolate the storage zone. Cement plugs are designed to be of sufficient length to provide a seal, which provides this isolation. In some areas, local regulations may require minimum plug lengths for well closure. Regulations may also require a plug across groundwater zones near the surface. Some operators close the well by filling the production casing with cement to surface. In the well closure design, operators must also account for any formations behind un-cemented casing in the well and for any equipment or hardware in the wellbore that may limit the operator's ability to properly place the cement plug. Prior to beginning well closure operations, operators kill the well and make sure that it is in a static condition. After completing the placement of plugs and allowing the cement to cure, operators verify the location and the seal of cement plugs in the well and then the well is capped and left with an identification monument, as required by regulations. After abandonment, some states require periodic review of the plugged well sites to confirm that a permanent seal is maintained.

4. Storage Well Operations

A. Well Integrity Evaluation (API 1171 Section 9)

Gas storage operators evaluate each individual well used for gas storage to determine its integrity and to ensure safe and environmentally responsible operations. Also included in the evaluation are third party wells that penetrate the storage reservoir and buffer zone or areas influenced by storage operations. As gas storage operators are not in control of third party wells, operators will have less information with which to assess the risks of such wells to storage operations.

Risk assessments are used as a basis for developing the integrity demonstration, verification, and monitoring tasks and for evaluating their frequency requirements. The operator's approach addresses the need for re-evaluation of risk-based conclusions, and the frequency of monitoring tasks.

Aspects of well integrity evaluation include the review of well design basis, drilling, completion and well workover records, wellhead inspections, casing inspections and other well logging, well pressure monitoring, and gas/fluid sampling. The outcome of these evaluations is a list of operating parameters for which operators specify bounds. Operators are putting in place monitoring systems to track the changes to these parameters with the goal of ensuring a well is always operated within its limits. Examples of parameters for which specific limits can be set include: wellhead injection and withdrawal pressures, tubing-casing annulus pressure if tubing is set on a packer, acceptable gas and fluid compositions, flow rate erosional velocity limits, operating temperatures, tubing and casing wall

thicknesses, subsidence rates in the area of the storage reservoir, operating limits to prevent hydrate formation, and maximum gas inventory.

Well operating limits will be re-evaluated upon changes to well configuration and/or condition. If a well experiences conditions outside of these limits, operators investigate the cause, document the circumstances, and determine what actions are needed to continue to operate the well.

B. Well Integrity Demonstration, Verification & Monitoring (API 1171 Section 9.3)

Operators are guided in the development of measures needed to demonstrate, verify and monitor integrity of storage wells by risk assessment. Risk assessment is not a one-time event, but rather an on-going process. Some of the factors used when verifying and demonstrating well integrity include well service life history, well design, well construction, maximum and minimum operating pressures (for injection, withdrawal and well treating), the nature of the product stored, the nature of the fluids produced, down hole and atmospheric corrosion, casing and tubing condition, the condition, depth and height of wellbore cement, the need for and types of emergency shutdown valves (surface or subsurface), how each well is operated, and the time interval since the most recent assessment and past assessment findings. Because storage wells are not all the same, risk profiles will vary and the resulting measures may also vary from well to well. There are, however, basic elements of well integrity that are evaluated and monitored at some frequency, as determined by the well's risk profile.

Visits by operating personnel to storage well sites provide opportunities for data collection as well as observations of overall conditions at the well sites. Such information is an important part of the data set needed for the Step 1 of a risk assessment. Risk assessment determines the frequency of well site visits. The general condition of the site, including the access road, fencing (if present), signage and other above-ground appurtenances is assessed by visual inspection. Encroachment activities that could impact the integrity of the well or well site are also noted and reported immediately. Operators also inspect well site valves and fittings for visual and/or auditory leaks. The inspection includes monitoring of casing pressure changes at the wellhead. If operators choose to employ leak detection technology, selection and usage decisions include factors such as detection limits for natural gas or any liquids, response time, reproducibility, accuracy, distance from source, background lighting conditions, geography and meteorology. Leak detection technology continues to evolve and operators deploy such technology when it is appropriate to do so as part of the risk-based continual improvement process.

Operators function-test the wellhead master valve and wellhead pipeline isolation valve(s) at least annually, or more frequently as determined by the risk assessment. Testing provides assurance that the valves will function as required to shut in and isolate the well for operational or emergency purposes. These valves are maintained to the same standard as other isolation valves. When testing reveals deficiencies and a valve does not meet functional requirements, the valve is repaired or replaced promptly so the well's ability to control and isolate fluid flow is not compromised.

When risk assessment indicates that emergency shutdown valves are needed, function-testing of these valves is performed at least annually or more frequently as determined by the risk assessment. The tests are conducted according to the manufacturer's recommendations and the operator's procedures. If an emergency shutdown valve on a storage well closes, it is not reopened remotely, but instead the operator reopens it manually at the well site after investigation into the cause of the closure.

Gas present in the annulus of wells can be, but is not always, an indication of loss of integrity. Storage operators collect and evaluate annular pressures and/or gas flow in cases where the outer annulus is left open. Annular pressure thresholds are determined (where not defined by regulation) from well integrity evaluation and risk assessment. The evaluation accounts for depth of casing strings on each side of the annulus, characterization of the annulus contents, pressure ratings of the casing strings and formation fluid pressures outside the casing strings. When annular pressure is detected, wellhead leaks can be eliminated or confirmed as the source of the annular gas by testing the wellhead seals where injectable packing and/or test ports are present. In some cases, annular gas can be sampled and analyzed to help determine the origin, since annular gas can occur from sources other than the gas storage reservoir.

Monitoring for defects, degradation, and corrosive and mechanical wear of tubular goods (casing, tubing or tubing/casing annulus) and evaluating the impact on well integrity is an on-going process. The frequency of monitoring is decided as part of the well integrity management plan and the underlying risk assessment that provides the basis for the integrity management plan. Tubular monitoring addresses:

- Evaluation of the integrity of the tubular goods and the identification of corrosion defects and other chemical/mechanical damage
- Corrosion potential of produced wellbore fluids and solids, including the impact of operating pressure and the analysis of partial pressures
- Corrosion potential of annular/packer fluid
- Corrosion potential of current flows associated with cathodic protection systems if applied to the well casing
- Corrosion potential of all formation fluids including fluids in formations above the storage zone
- Corrosion potential of un-cemented casing annuli including static liquid levels
- Corrosion potential of adverse current flows associated with cathodic protection systems from nearby pipelines and other production facilities

There are numerous methods used to monitor downhole conditions, including corrosion, and operators evaluate which methods to employ based on well configuration and risk assessment. Evaluation of well information, hazards and threats and the likelihood and consequence of failure drive decisions regarding tool usage and frequency of deployment for monitoring downhole conditions. When operators remove tubular goods during workovers and corrosion products are visible, samples can be sent for metallurgical analysis to help determine the cause and mechanisms of the corrosion. Some of the other tools used to evaluate downhole conditions (including corrosion) in tubing and/or casing include:

- Temperature, differential temperature and/or noise logs to look for anomalous readings that could indicate fluid movement behind pipe
- Neutron logs to look for accumulations of gas in formations outside the storage zone(s)

- Eddy-current/magnetic flux leakage logs to help determine inner and outer wall metal loss and pipe defects
- Caliper logs to evaluate inside diameter, internal corrosion and defects
- Cement bond logs to help determine cement tops and bond quality to the casing and to the formation
- Segmented bond logs to look for cement channeling
- Downhole cameras for visual inspection of the inside of the casing or tubing
- Ultrasonic imaging logs to help determine cement channeling, internal diameter, wall thickness, pipe eccentricity and defects
- Electromagnetic casing potential logs to help identify axial and radial current density, corrosion rate, external corrosion location and casing thickness

These specialized tools require specific wellbore conditions and technicians to run them and to evaluate the results. Different tools evaluate different properties of metal, fluids or voids, including anomalous readings, gas behind pipe, fluid movement, corrosion potential, metal loss (wall thinning, pits) and other defects (split pipe, ovalities, kinks, holes). Operators determine which (if any) of these tools are appropriate to use as a means of gathering data to aid in the assessment of the as-current health of key components of the well barrier envelope. These data can be part of a risk reduction program when increased or additional monitoring is indicated.

When new wells are drilled, baseline logs are run to aid in future well integrity monitoring, including logs that evaluate changes in gas located behind casing (for example neutron logs) and the condition of newly installed casing (for example magnetic flux leakage or acoustic-type casing inspection logs). Baseline logs help determine anomalies present when the pipe is first installed, and since new installed wells are tested for mechanical integrity prior to being placed in service, the presence of these same anomalies on future logs can be explained. Future log runs are useful to follow the progress of any anomalies detected and, with the aid of risk assessment, they can help operators determine when mitigative steps are needed.

Risk assessment is holistic, in that all threats to the integrity of the gas storage facility are evaluated. In addition to wellhead and wellbore mechanical damage and corrosion, operators evaluate the effects of flow erosion, hydrate forming potential, facility component flow capacity and corrosive potential of fluids present across the gas flow rate and pressure operating envelope for the facility.

Operators use the monitoring of well pressure (including shut in wells) as a means of demonstrating on-going well integrity. Unanticipated changes to historical trends are investigated and findings and corrective actions are noted for future reference. Many times these changes are operational issues (such as faulty instrumentation) and explainable, but these anomalies deserve careful evaluation since they can also be early warnings of potential loss of well integrity.

C. Well Barriers and Potential Leak Paths (API 1171 Section 9.3)

Operators have designed and installed a number of different well completions depending on their historical experiences, practices, and site-specific conditions. A common well completion case referenced herein contains production casing without tubing. The primary root cause mechanisms for storage gas well releases for this completion are 1) wellhead component or seal failure; 2) production casing leak; or 3) a downhole annular barrier breach (i.e. cement sheath). These primary leak paths are depicted on the schematic in Appendix 5 Gas Storage Well Configuration: Example C and described more fully below:

1) Wellhead component or seal failure

This leak path occurs when the primary and secondary seals in the wellhead fail, allowing gas in the production casing to migrate past the seals into the production casing annulus. Leaks can also occur as a result of mechanical failure of other wellhead components such as casing slips, which can allow the production casing to drop free of the wellhead seal assembly. Observations that indicate a potential leak may exist include an increase in annular pressure or flow, dependent on the annular valve position during normal well operation mode.

For a release to occur, an initial failure takes place allowing pressurized storage gas to leave the production casing. Gas then either exits through an open annular valve or pressures up the annulus, if closed. To eliminate this type of release to the atmosphere, some operators close the annular valve while the well is in operational mode. However, if pressurized gas is trapped in the annulus and not allowed to dissipate, there is a possibility of additional secondary failures that will lead to more complex, and difficult to control, release paths, hence other operators leave the annular valves open in normal operational mode.

Diagnosing the failure mechanism requires the operator to perform one or more of the following operations; test wellhead seals, observe wellhead components for indications of leakage (noise and/or hydrate deposition), and/or perform interference testing between the production casing and production casing annulus to determine if the leak is at the surface or downhole. Leak resolution may include replacing the wellhead assembly or wellhead seals and/or repair or partial replacement of the production casing. Preventive measures such as wellbore integrity inspections, mechanical integrity testing, and annular barrier monitoring and evaluations may identify potential direct cause failure mechanisms before they occur.

2) Production casing leak

This leak path occurs when the production casing wall is breached. Causes include but are not limited to production casing failure due to reduced casing wall thickness from corrosion and/or the introduction of higher pressures than containable for stimulation treatments, or production casing wall collapse from outside forces such as earth movement or foreign production operations. Observations that indicate a potential leak may exist are lower than expected shut-in pressures or gas exiting somewhere outside of the structure of the wellbore.

The stored gas can escape outside the structure of the storage wellbore from deep underground and migrate through a path of least resistance upward until it reaches an alternative escape path. The escape path could be through an oil and gas, water, or abandoned well completed in a shallower permeable formation or the path could be all the way to an escape at the surface. Operators must understand subsurface geologic conditions to assess the risk of geologic migration.

Diagnosing the failure mechanism requires the operator to perform one or more of the following operations: obtain electric logs (pipe inspection, caliper, gamma ray-neutron, differential temperature, noise, spinner flow survey, etc.); install a bridge plug and pressure test the casing. Options for the operator to resolve the breach may include partially replacing the production casing, installing a casing internal patch, cladding, or liner, and/or remedial cementing. Preventive measures such as wellbore integrity inspections, mechanical integrity testing, and annular barrier monitoring and evaluations may identify potential direct cause failure mechanisms before they occur.

3) Downhole annular barrier breach

This leak path occurs when gas and/or hydrostatic pressure in the annulus exceeds the strength of the rock below the intermediate or surface casing shoe, resulting in establishment of an escape path outside the wellbore. Observations that a potential leak may exist are gas exiting somewhere beyond the structure of the wellbore.

In this case storage gas finds a path of least resistance around the intermediate casing shoe and then into the subsurface lithology where it could enter an oil and gas, water, or abandoned well completed in a shallower permeable formation, or migrate all the way to an escape at the surface.

Diagnosing the failure mechanism requires the operator to obtain electric logs (gamma ray-neutron, differential temperature, ultrasonic/noise, etc.) as needed to determine the direct cause. In order to resolve this breach, the operators will usually require remedial cementing. Preventive measures such as wellbore integrity inspections, mechanical integrity testing, and annular barrier monitoring and evaluations may identify potential direct cause failure mechanisms before they occur.

Note: for any gas release path scenario, failure of one or more barriers to storage gas containment must occur. Proactive wellbore integrity inspections and annular barrier monitoring and evaluations that result from a site-specific risk assessment model are key elements to identifying and resolving a direct failure mechanism before it occurs.

D. Site security, inspections and emergency response (API 1171 Section 10)

Storage operators assess and monitor the security and safety of their well sites and have an emergency plan in place in the unlikely chance of an event. The overall goal of the plan is to reduce the potential for an incident and to ensure the safety of the public, operating personnel, contractors, property and the environment. Thorough preparation and training enables operating personnel to recognize and respond to abnormal operating conditions or to changes in site security in a timely manner so as to minimize or prevent impacts.

Due to the variety of designs for downhole and wellhead facilities, the potential failure modes of a well can be different from well to well even in the same field. Likewise, utilization of adjacent lands by the surface owner and wellsite configuration also add diversity. Therefore, the safety and security plan are site-specific and are determined by the operator's risk assessment.

Operators take additional steps to maintain site security and safety by limiting access during drilling, workover, wireline logging and other similar activities. Additionally, operators can use fencing, barricades and other barriers to restrict access during on-going operations as determined through their site-specific assessments. The implemented security and safety measures are influenced by the well's flow potential, location, population density, natural forces, terrain and environment adjacent to the

wellsite. Operators are aware of potential ignition sources on the wellsite during well work and locate such potential ignition sources in a manner that provides for on-going safety.

Site inspections to review the safety and security of storage facilities at the well site are performed on a regular and periodic basis. Inspections are often concurrent with the collection of well data, such as annular pressures, mechanical integrity inspections, or other operational activities such as opening or closing the well. Changes in the status or condition of an item being utilized in the risk analysis are reported to the storage personnel responsible for the risk analysis process. This change will then be utilized in the next iteration of the risk analysis and the operator will implement new, additional and/or different risk preventive and mitigative measures, if necessary.

To ensure consistency and the collection of accurate information, operators are developing forms listing the inspection criteria and training personnel in how to conduct the inspection. The inspection results are saved according to the operator's document retention policy.

Operators are developing, implementing and updating emergency preparedness/response plans that cover accidental releases, equipment failures, natural disasters and third party damages. Gas storage plans are incorporated into the operator's existing emergency procedures for the pipeline system and include personnel roles and responsibilities, emergency contact information, communication protocol, procedures for response to leaks, fires and uncontrolled well releases and other information and tasks as further detailed in API 1171. Operators are training personnel using the emergency response plan. Often, operators contact local emergency responders and discuss incident scenarios and potential response alternatives.

A key component of an underground storage operator's emergency response plan that is unique to well operations is a well emergency plan which treats loss of containment or loss of control incidents occurring during well drilling, servicing or operating. Due to the potential wide variety of well emergencies, the operator's plan needs to be flexible. The plan identifies the procedures, equipment and personnel needed to respond to the situation.

E. Procedures and training (API 1171 Section 11)

Operators are updating existing and developing new processes and procedures to identify and address the safe operation, maintenance and inspection of storage wells, consistent with requirements, safety policies, regulations and applicable standards. The authors have existing safety processes and procedures established to conform with basic well safety established by state regulatory authorities or the operator's prudent practices.

As stated previously, gas storage operators are in various stages of establishing conformance with API 1171 guidance. Operators are conducting gap analyses between their current practices and API 1171 with respect to procedures and training. Closing the identified gaps to align with API 1171 is part of the process expected to be performed within the 7-10 years following a final rulemaking.

Procedures address all operations phases, including:

- Initial startup (new, modified, or acquired facilities)
- Normal operations
- Temporary operations as needs arise

- Normal shutdowns
- Emergency operations, including emergency shutdowns
- Start-up or restoration of operations following maintenance

Procedures are put in place prior to the development of a new storage facility, and address the minimum requirements for construction including drilling and other well entry work, reservoir integrity monitoring and management, operations and maintenance, emergency response, control room communications and responses, personnel safety, safety management systems, and site-specific procedures determined to be necessary by the operator.

Operators are training personnel responsible for operating, maintaining, and monitoring storage wells and reservoirs in accordance with their duties and responsibilities. Training addresses operating procedures, safety procedures, recognition of abnormal operating conditions and emergency conditions. Training programs can consist of methodologies including, but not limited to classroom, computer-based and on-the-job training. Operators review training programs periodically to determine effectiveness. Training programs are modified when changes occur in technology, processes, procedures, or facilities. Operators evaluate the effectiveness of training to verify that persons assigned to operate and maintain storage wells and reservoirs possess the knowledge, skills, and abilities necessary to carry out their duties and responsibilities including those required for start-up, operation and shutdown of storage facilities. Personnel are trained on the site-specific procedures necessary for operation of storage wells and reservoirs, as well as trained on the recognition of abnormal operating conditions. Reporting requirements, documentation, and recordkeeping requirements are included in the training.

Integrity Management programs also integrate storage well and reservoir elements so that procedures and programs work together to promote the integrity of the storage facility. Data required include geologic information on the formations penetrated by the storage well, wellbore configuration and completion data (e.g. casing characteristics, setting depths, cement, etc.), pressure and volume data on the flow capability of the well and reservoir, annular pressure and/or volume data, reservoir fluid analysis, wellhead design, and other characteristics of the subsurface in addition to information about the wellsite.

Operators establish regular review frequencies for the procedures and use management of change to provide for orderly review and acknowledgement of changes and the impacts to integrity and safety. Procedures are modified to account for changes in operating conditions, advancements in technology, regulatory changes, abnormal operating conditions, or as experience dictates.

Operators retain the records necessary to administer the procedures and establish retention requirements for specific records. Whenever changes are made to the operating procedures, operating personnel are notified and trained as necessary and the training is documented. Records management includes requirements for identification, collection, storage, protection, retrieval, retention time and disposition of records.

Operators maintain records of well configuration (as-built), well construction and well work activities for the life of the facility. These records include, as applicable and available:

- Wellhead equipment and valves
- Well casing
- Casing cementing practices
- Completion and stimulation
- Monitoring of construction activities
- Testing and commissioning
- Well remediation
- Well closure

Operators use pipeline public awareness and damage prevention communications that include information regarding the utilization of damage prevention notification systems, education of the public on the hazards related to unintended releases, indications of a release, procedures for reporting the release and actions to be taken for public safety during the release.

Appendix 1

Background - Underground Storage of Natural Gas in the U.S.

SUPPORTING THE AMERICAN WAY OF LIFE

THE IMPORTANCE OF NATURAL GAS STORAGE

energy API INGAA AGA American Gas Association

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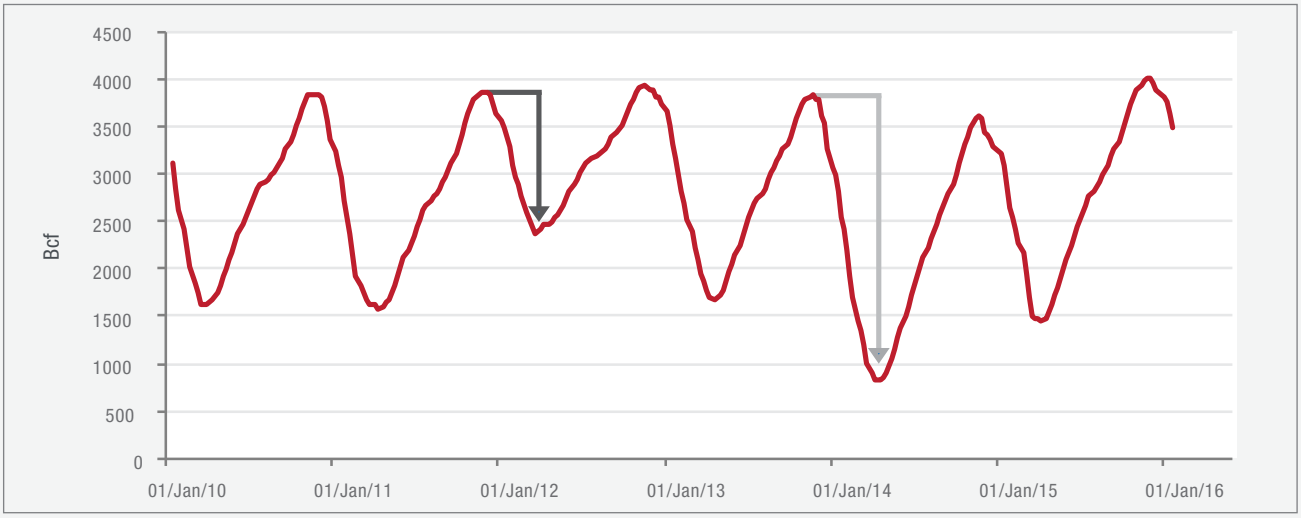
WHERE NATURAL GAS STORAGE IS LOCATED?

Underground storage of natural gas is an integral component of the nation's energy system, and our nation's significant storage capacity enables utilities to offer clean natural gas to consumers throughout the year with reliable service and prices.[1]

This use results in significant seasonal variations in which natural gas consumption is highest during the winter time and lowest during mild-weather months. Natural gas storage enables supply to match demand on any given day throughout the year.

Natural Gas Working Storage Levels

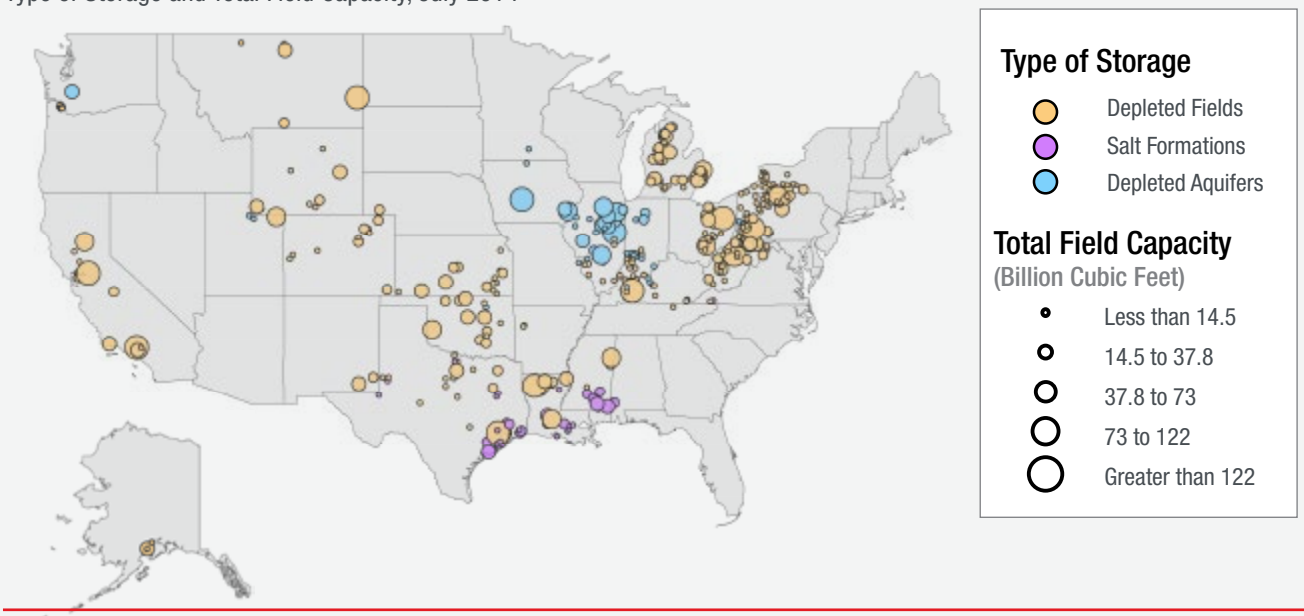
Energy Information Administration, "Weekly Natural Gas Storage Report, History," January 8, 2016.



The chart above shows how storage fluctuates with the weather. During the mild winter of 2012, the gas withdrawn from storage was far more moderate (see black arrow). In contrast, in 2014, the year of the Polar Vortex, natural gas storage was "drawn down" sharply (see grey arrow). But even in the mildest of winters, such as 2012, natural gas withdrawals from storage were vital to meeting winter natural gas demand.

Where Natural Gas Underground Storage Fields are Located

Type of Storage and Total Field Capacity, July 2014



[1] Energy Information Administration, "Natural Gas Explained, Use of Natural Gas," accessed January 15, 2016, http://www.eia.gov/energyexplained/index.cfm?page=natural_gas_use

NOTE: that the map includes both active and inactive fields.

SOURCE: EIA Energy Mapping System; EIA-191 Monthly Underground Gas Storage Report July 2014

HOW IS NATURAL GAS STORED?

How is Natural Gas Stored?

Natural gas is stored underground primarily in three reservoir types: depleted oil and gas fields, depleted aquifers, and in salt beds and salt caverns. Natural gas may also be stored above ground in refrigerated tanks, as liquefied natural gas (LNG).

Types of Natural Gas Underground Storage

Depleted Natural Gas or Oil Fields

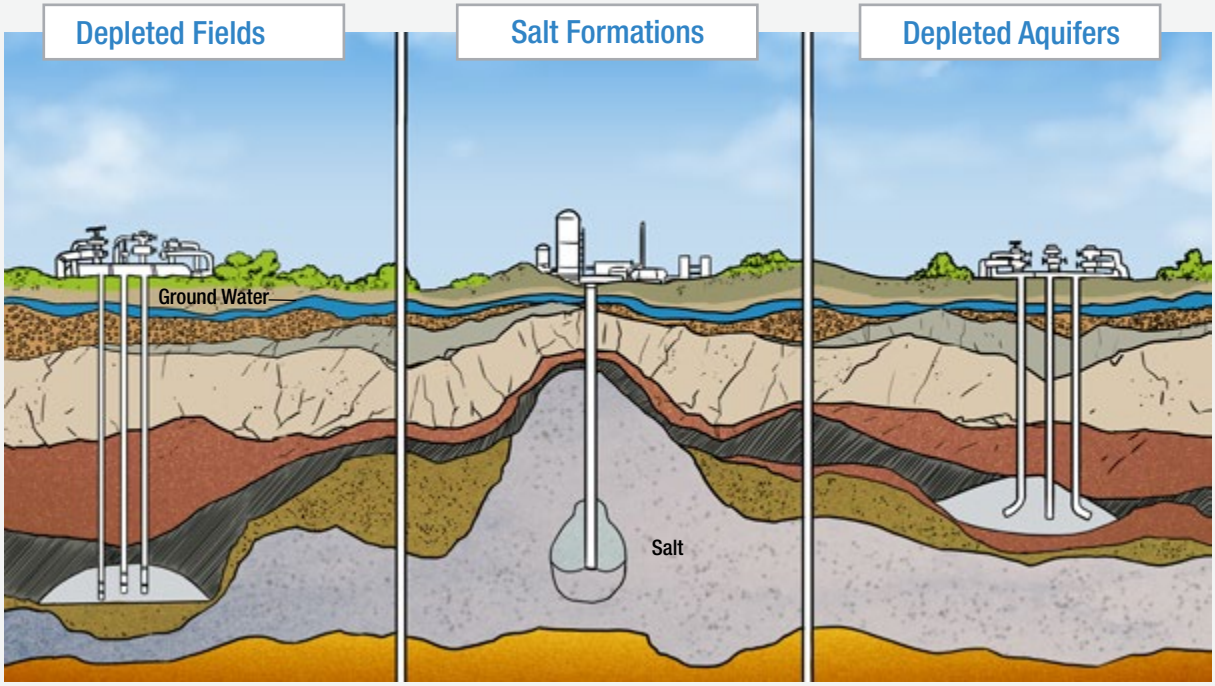
Of the approximately 400 active underground storage facilities in the U.S., about 79 percent are depleted natural gas or oil fields. Conversion of an oil or gas field from production to storage takes advantage of existing infrastructure such as wells, gathering systems, and pipeline connections. Depleted oil and gas reservoirs are the most commonly used underground storage sites because of their relatively wide availability.

Salt Formations

Salt formation storage facilities (also known as salt caverns or salt beds) make up about 10 percent of all facilities. These subsurface salt formations are primarily located in the Gulf Coast states. Salt formations provide very high withdrawal and injection rates.

Depleted Aquifers

Natural aquifers may be suitable for gas storage if the water-bearing sedimentary rock formation is overlaid with an impermeable cap rock. They are not part of drinking water aquifers and make up only about 10 percent of storage facilities.



SAFETY IN UNDERGROUND STORAGE OF NATURAL GAS

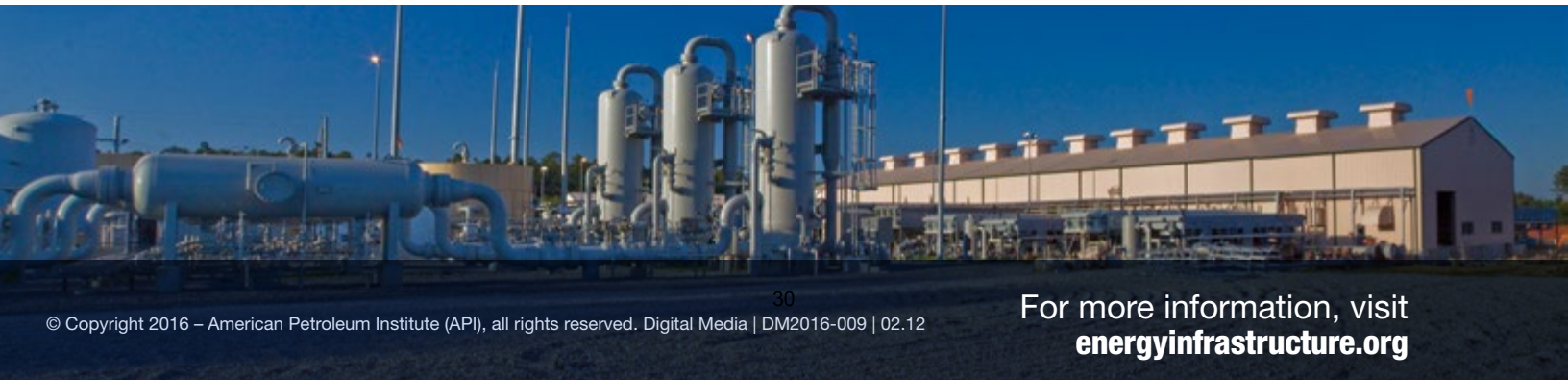
Underground natural gas storage operators are committed to ensuring the safety and integrity of their facilities. The industry's construction, operation and integrity management protocols are overseen by multiple agencies at the state and federal level with jurisdiction over underground storage facilities:

- The Federal Energy Regulatory Commission (FERC) regulates projects connected to interstate pipeline systems. FERC is responsible for authorizing the construction or expansion of storage facilities and the terms and conditions of service (i.e., open access) and the rates charged by these providers.
- The Pipeline and Hazardous Materials Safety Administration (PHMSA) is authorized to regulate the safety of natural gas transportation and storage.
- Intrastate storage may fall under the regulatory authority of various state government entities depending upon the state. For example, underground storage in Texas is under the authority of the TX Railroad Commission – Oil & Gas Division. Often state utility commissions as well as state environmental or natural resource agencies set the rules governing intrastate underground storage.

Beyond federal and state regulation, industry has taken the initiative to work with external stakeholders to develop two recommended practices (RPs)—accredited by the American National Standards Institute—for underground storage. RP 1170 and 1171 provide guidance to operators on how to design, operate, and ensure the integrity of underground storage for natural gas.

Underground Storage by the Numbers

- Approximately 400 active storage facilities in 30 states, made up of depleted natural gas or oil fields (80%), depleted aquifers (10%) and salt caverns (10%)
- Approximately 20% of all natural gas consumed during the winter is supplied by underground storage
- Underground storage capacity increased 18.2% between 2002 and 2014
- Approximately 4 trillion cubic feet of natural gas can be stored underground, or enough to meet an average states residential natural gas consumption for more than 20 years



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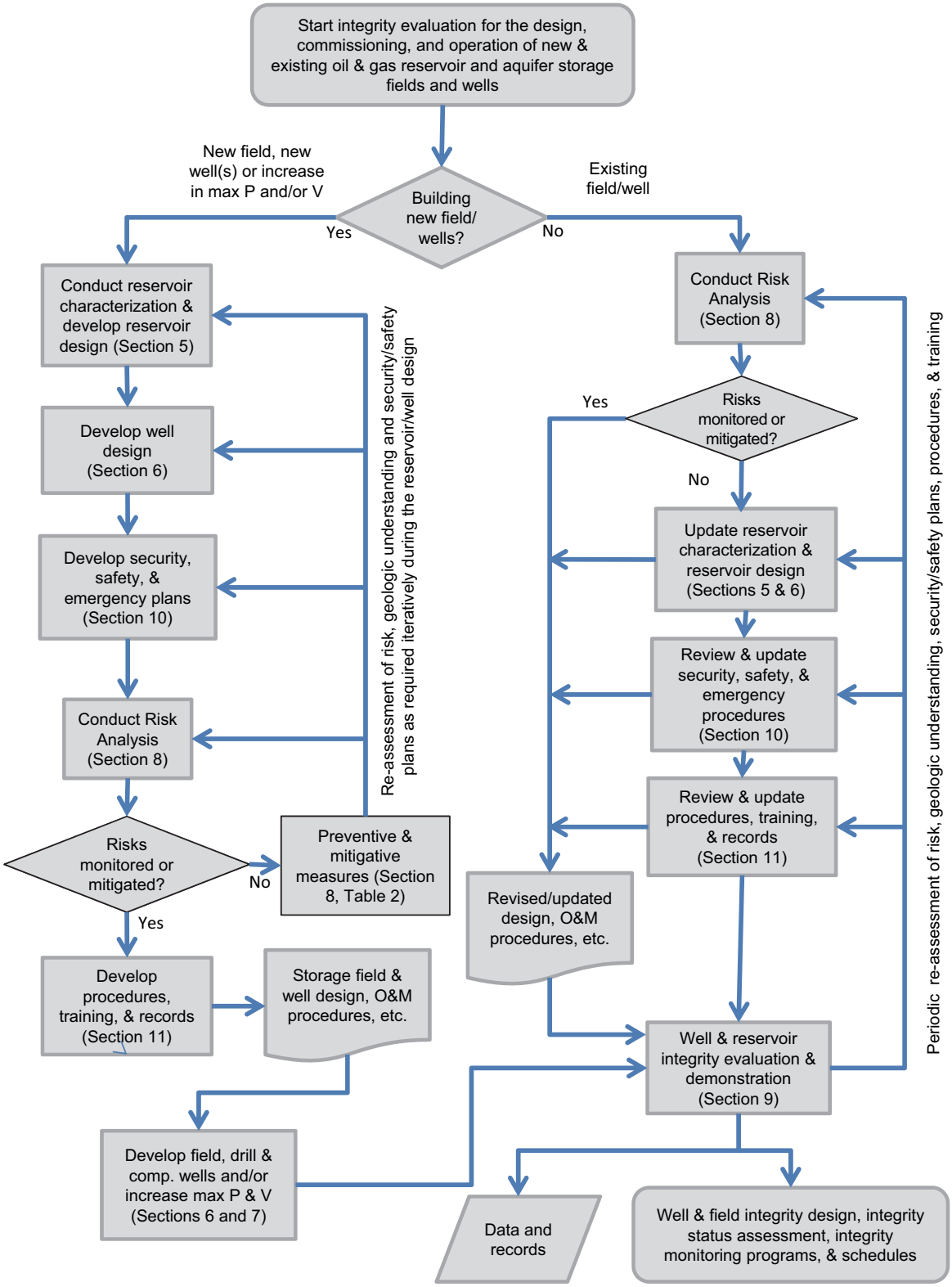
Appendix 2
Various Steps for Well & Reservoir Integrity Management Evaluation

Source: API Recommended Practice 1171, Figure 1



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Appendix 3
Storage Well Potential Threats and Consequences

Source: adapted from API Recommended Practice 1171, Table 1

Threat or Hazard	Threat/Hazard Description	Potential Consequences
Well integrity (corrosion, material defect, erosion, equipment failure, annular flow)	Gas containment failure due to inadequately sealed storage well(s), e.g. casing corrosion, cement bond failure, material defect, valve failure, gasket failure, thread leaks, etc.	• Loss of stored gas inventory • Damage to well site facilities and equipment • Safety hazard to company personnel and the public • Loss of use of water sources and/or wells • Decrease or loss of field performance
Design	Gas containment failure due to inadequate completed wells, sealed plugged well(s), failure of cement squeeze job perforations or stage tool, pressure rating of components, etc.	• Release of gas to the atmosphere • Damage to well site facilities and equipment • Safety hazard to company personnel and the public • Loss of use of water sources and/or wells • Loss of stored gas inventory • Decrease or loss of field performance
Operation and maintenance activities	• Inadequate procedures • Failure to follow procedures • Inadequate training • Inexperienced personnel and/or supervision	• Loss of stored gas inventory • Damage to well site facilities and equipment • Safety hazard to company personnel and the public • Loss of use of water sources and/or wells • Decrease or loss of field performance
Well intervention	Gas containment failure due to loss of control of a storage well while drilling, reconditioning, stimulation, logging, working on downhole safety valves, etc.	• Damage to drilling rig or service rig • Loss of tools in wellbore • Hazard to operator and service company personnel • Safety hazard to public • Decrease or loss of field performance • Loss of well
Third party damage (intentional/ unintentional damage)	Intentional/ unintentional damage	• Accidental impact by moving objects (e.g. farm equipment, cars, trucks, etc.), vandalism, terrorism that could result in damage to facilities: o Loss of ancillary facilities o Well on/off status change o Impact to service reliability o Impact to neighboring public, storage gas loss
Outside force-natural causes	Weather related and ground movement	• Heavy rains, floods, lightning, earth movements, groundwater table changes, subsidence, etc. that could result in: o Damage to facilities/impact to service reliability

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Appendix 4
Storage Well Preventive and Mitigative Programs

Source: adapted from API Recommended Practice 1171, Table 2

Threat or Hazard	Preventive/Mitigative Treatment or Monitoring Programs
Well integrity (corrosion, material defect, erosion, equipment failure, annular flow)	• Casing condition and inspection program • Monitoring pressure, rate and inventory • Cement analysis and evaluation • Internal corrosion monitoring • Plugged and abandoned well review and surveillance • Monitor annular pressures, rates, or temperatures • Subsurface and surface shutdown valves • Monitor cathodic protection as applicable • Operate, maintain and inspect valves and other components
Design	• Collect and evaluate plugged and abandoned well records and rework or plug • Develop design standards for new wells • Evaluate current completion of existing wells for functional integrity and determine if remediation monitoring is required
Operation and maintenance activities	• Procedures • Training of personnel and contractors and establishment of procedures
Well intervention	• Implement training and safety programs for company and contractor personnel • Develop detailed drilling and well servicing procedures

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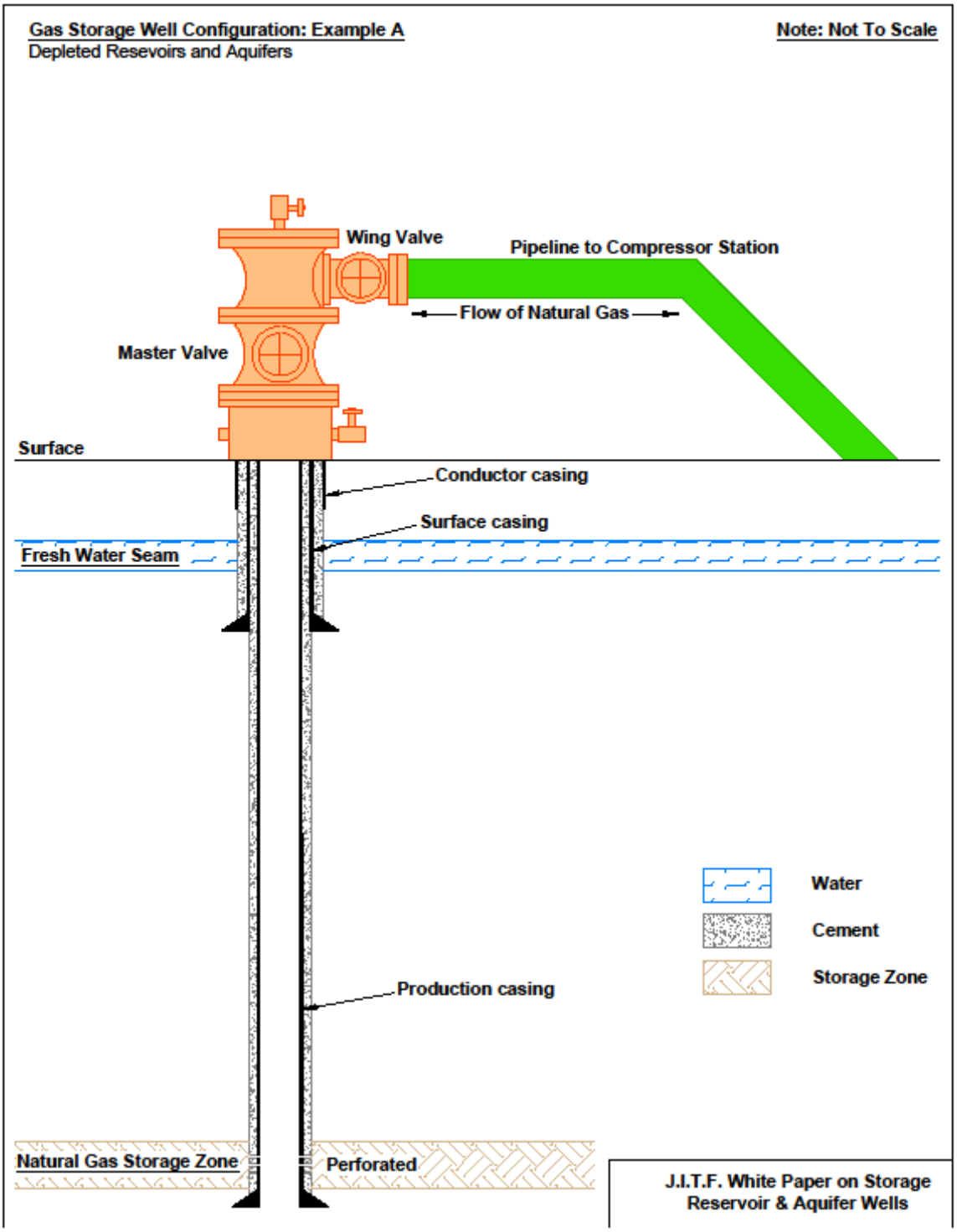
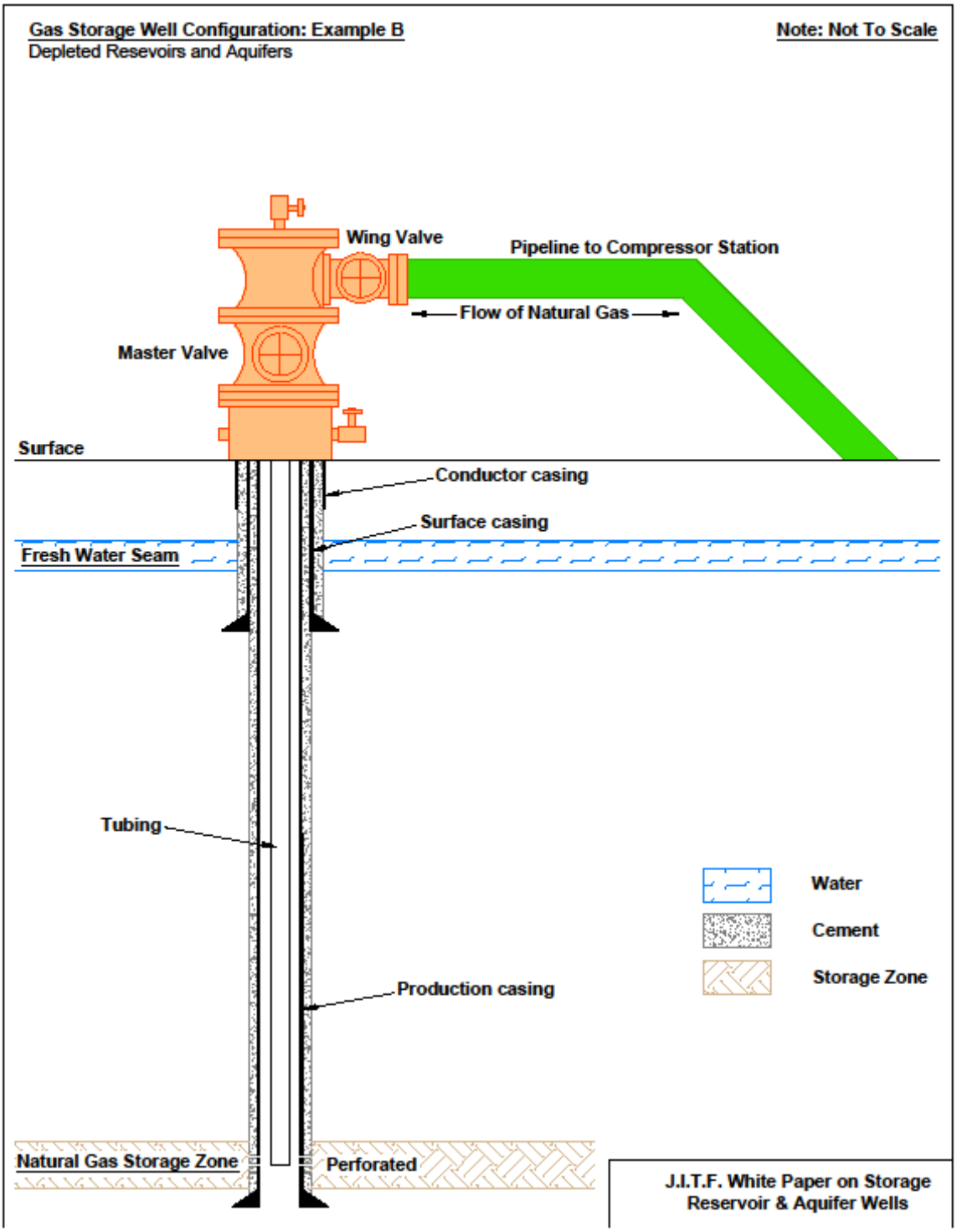
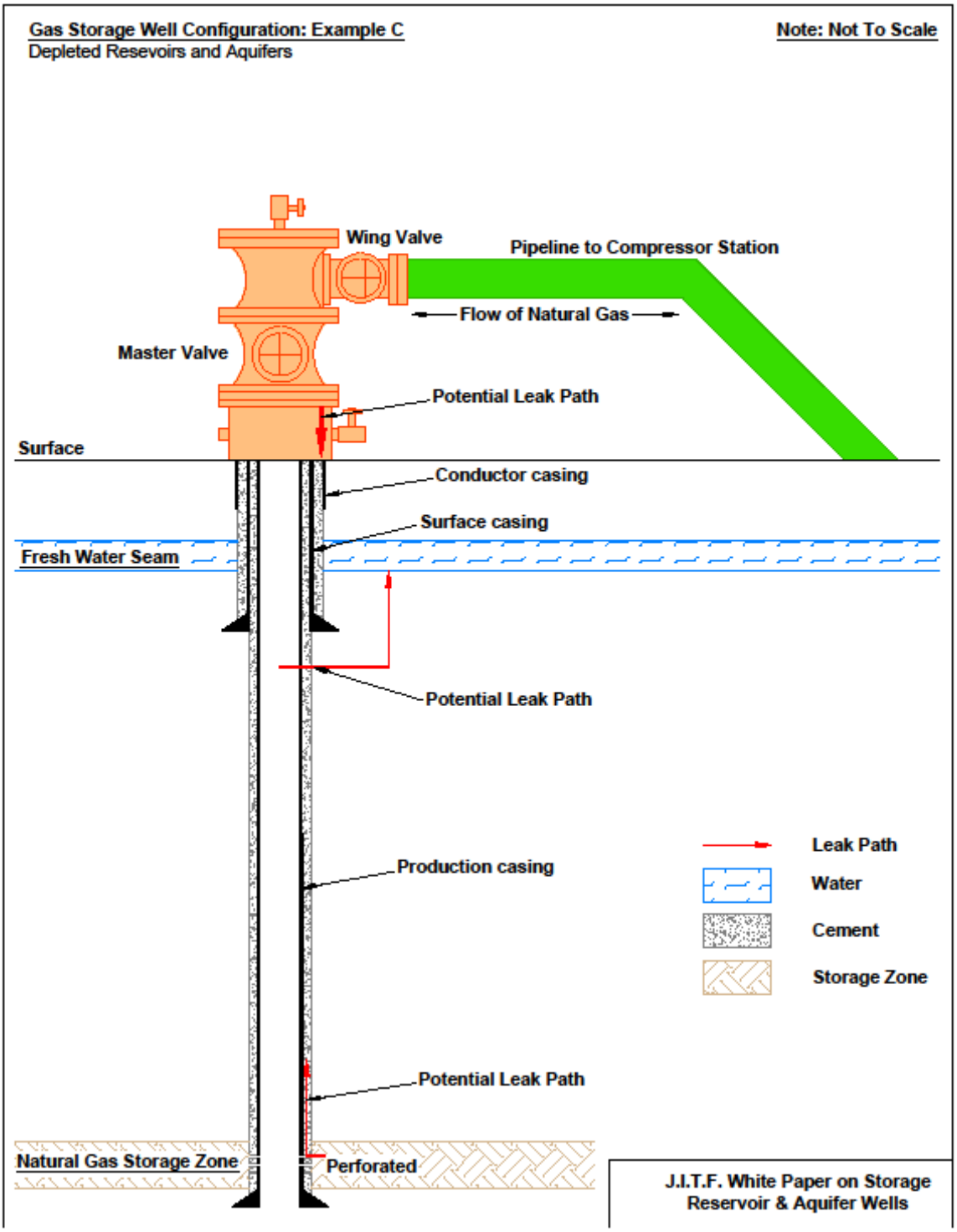
Appendix 5

Well Configuration Examples A, B, and C


Gas Storage Well Configuration: Example A
Depleted Resevoirs and Aquifers
Note: Not To Scale
Wing Valve
Pipeline to Compressor Station
Flow of Natural Gas
Master Valve
Surface
Conductor casing
Surface casing
Fresh Water Seam
Water
Cement
Storage Zone
Production casing
Natural Gas Storage Zone
Perforated
J.I.T.F. White Paper on Storage
Reservoir & Aquifer Wells


Gas Storage Well Configuration: Example B
Depleted Resevoirs and Aquifers
Note: Not To Scale
Wing Valve
Pipeline to Compressor Station
Flow of Natural Gas
Master Valve
Surface
Conductor casing
Surface casing
Fresh Water Seam
Tubing
Water
Cement
Storage Zone
Production casing
Natural Gas Storage Zone
Perforated
J.I.T.F. White Paper on Storage
Reservoir & Aquifer Wells


Gas Storage Well Configuration: Example C
Depleted Resevoirs and Aquifers
Note: Not To Scale
Wing Valve
Pipeline to Compressor Station
Flow of Natural Gas
Master Valve
Potential Leak Path
Surface
Conductor casing
Surface casing
Fresh Water Seam
Potential Leak Path
Production casing
Leak Path
Water
Cement
Storage Zone
Potential Leak Path
Natural Gas Storage Zone
Perforated
J.I.T.F. White Paper on Storage
Reservoir & Aquifer Wells

Appendix 6

Emergency Shutdown Valve Systems in Natural Gas Storage Wells: Application, Historical Use and Reliability, and Risk Assessment for Decision-Making in Regard to Application

Executive Summary

This Appendix explains Emergency Shutdown Valve (ESV) systems, their use and application in natural gas storage, operating experience and reliability, standards and regulations, and risk assessment related to decision-making on ESV application. ESVs can be installed above ground as Surface Safety Valves (SSV) or below ground as Subsurface Safety Valves (SSSV). Above ground systems are much easier to assess, test, and maintain, but their ability to provide physical barrier control can be limited if the wellhead becomes damaged. Underground valves can sense abnormal surface conditions and close, but are more difficult to operate and, in the experience of this Joint Industry Task Force (JITF) team, have additional issues that affect reliability and safety. Based on industry surveys, this team estimates that approximately three to five percent of storage wells currently have SSSVs. This Appendix explains ESV systems, summarizes some available reliability information, summarizes the benefits and reliability issues experienced by storage operators, and provides storage operator industry perspective. Appendices provide company operating experience testimonials, literature reviews of ESV reliability and risk management guidance.

Natural gas storage operators have consistently provided safe and reliable natural gas storage. As natural gas storage is critical for meeting peak hourly, daily and seasonal user demand for natural gas, natural gas storage operators are continually searching for new equipment, processes, and methodologies to improve safety and reliability. ESVs have a long operating history in natural gas storage fields. Gas storage operators have employed SSSVs since the 1960s and 1970s. SSSV use increased in the 1980s and 1990s in production and storage settings. Natural gas storage operators began installing SSSVs within their storage wells to act as a physical control barrier, activating during pressure, temperature, or surface damage events. Several companies within the natural gas storage industry embraced SSSVs to provide an additional barrier control for high risk storage wells. Operators began installing SSSVs at locations of concern such as roadways or near homes to provide an additional level of safety in case a breach at the wellhead occurred. In the period since their first installations, storage operators have gained experience with operating and maintaining SSSVs, have a better understanding of their safety benefits, and have learned the additional reliability challenges and risks that come with their application.

The benefits of ESV systems include risk reduction related to consequence mitigation by limiting the magnitude and duration of an event that occurs downstream of the valve. The ESV system provides a means of automatic or controllable shut-off of flow and thus could have a protective effect to places of habitation, roads, human gathering places, environmentally sensitive areas, other industrial infrastructure, including inter-related gas storage facilities, or other sensitive receptors. The fail-safe, automatic or controllable functionality of ESV systems protect against uncertain events such as natural forces (earth movements, seismic activity, floods, severe weather events and other earth forces) or human-induced activity that could have adverse impact on well integrity. ESV system technology is a proven technology that has been extended to wider applications in terms of depth, location, diameter and pressure-temperature-flow regimes.

In the period since the 1960s, natural gas storage operators have observed a variety of challenges associated with ESV system use in the subsurface (SSSV), including the impairment of storage service reliability, increased risks to field operators (workers) and the public due to increased well re-entry (service) rates and related loss-of-containment potential, and increased challenges with emergency intervention operations. SSSV do not arrest all leaks, only those severe enough to activate the valve. A

shallow SSSV installation does not shut-down the flow of gas through a deep casing breach or other event upstream of the valve. Shallow SSSVs are designed to limit the amount of escaping gas in a catastrophic surface or near-surface event. SSSVs might not seal gas tight over time because the conditions in which they operate are harsh in terms of exposure to high velocity, large pressure variations, liquids, sand and other particulates.

Key observations discussed in this Appendix include:

1) ESV systems are a physical control, or barrier, requiring a specific set of conditions in order to activate.
2) An ESV system, if functioning properly during the specific event for which it was designed, can reduce the consequences of an event by minimizing duration and impact.
3) ESV system valve setting (location in the well) determines the risk reduction benefit for a particular event.
4) ESV in the downhole well environment have reliability and safety issues:
    a. Reliability rates (Mean Time to Failure (MTTF), Mean Time to Repair (MTTR)) have well-established ranges for immediate service impacts (corrective maintenance) as well as longer-term functional failures requiring well re-entry and repair or replacement (based on industry literature review and storage operator testimony).
    b. SSSVs can have service reliability impairment due to tubing string/ valve flow diameter restrictions along some length of the wellbore (storage operator testimony).

Table 1. Probability Descriptors per the Center for Chemical Process Safety (CCPS) American Institute of Chemical Engineers (AIChE)

Descriptor	Decimal Notation	Scientific Notation
	(Incidents per well-year)	(Incidents per well-year)
Likely	> 0.01	> 1.0E-02
Unlikely	0.001 to 0.0099	1.0E-03 to 9.9E-03
Very Unlikely	0.00001 to 0.00099	1.0E-05 to 9.9E-04
Extremely Unlikely to Remote	< 0.00001	< 1.0E-05

5) SSSVs can mitigate the impact of a casing or casing/cement system loss-of-control/loss of containment event. The frequency of these events - as established in industry literature for the broader applications in the oil and gas exploration and production industry - is “very unlikely” (The Center for Chemical Process Safety defines “very unlikely” as in the range 1E-05 to 0.99E-04 per well-year – Table 1). Natural gas storage well casing failure and cement failure rates are in the “very unlikely” range of E-05 per well-year. Wells with two or more passive physical barriers (such as a casing string and a full cement sheath, etc.) have failure rates at least one order of magnitude less than a single technical barrier system, AND have inherent reliability if there is no degradation of these barriers by time-dependent decay modes such as corrosion. Failure rates quoted here are from industry surveys and literature sources referenced in this Appendix, including published papers from the Society of Petroleum Engineers, and the March 2005 report to the Gas Research Institute under Contract No. 8604, Project No. 809833, “Risk Assessment Methodology For Accidental Natural Gas and Highly Volatile Liquid Releases From Underground

Storage, Near-Well Equipment," prepared by Glenn DeWolf, Katherine Searcy, Douglas Orr and Christopher Loughran on behalf of URS Corporation.

6) Wells with an SSSV can provide the entire well system with a failure rate of up to one order of magnitude less than that for a well system with only one physical passive barrier; however, SSSV have reliability weaknesses which increase the number of well re-entries and erode the risk reduction benefit by service impairment, service reliability impairment, and increased risk of loss of containment and increase the risk of worker safety due to well re-entry for servicing, repairing, or replacing the SSSV. The information to support the conclusion is from storage operator testimony, industry literature, and the Gas Research Institute report noted in conclusion #5.

Conclusions and Recommendations

Based on the operational knowledge of those assisting in the creation of this Appendix, and the research conducted by this team, there are advantages and disadvantages associated with SSSV.

The benefits include risk reduction related to consequence mitigation by limiting the magnitude and duration of an event that occurs downstream of the valve. The ESV system provides a means of automatic or controllable shut-off of flow and thus could have a protective effect to places of habitation, roads, human gathering places, environmentally sensitive areas, other industrial infrastructure, including inter-related gas storage facilities, or other sensitive receptors. The fail-safe, automatic or controllable functionality of ESV systems protects in particular against uncertain events such as natural forces (earth movements, seismic activity, floods, severe weather events, and other earth forces) or human-induced activity that could have adverse impact on well integrity. ESV system technology is a proven technology that has been extended to wider applications in terms of depth, location, diameter and pressure-temperature-flow regimes.

The disadvantages of ESV systems, particularly SSSVs, include functional reliability weaknesses for components of ESV systems, potential impairment of storage service reliability, increased risk to workers and the public due to increased well re-entry (service) rates and related loss-of-containment potential, and increased challenges with emergency intervention operations.

Therefore, it is recommended that the natural gas storage industry support, develop, and implement risk-based integrity management plans to mitigate risks, reduce potential adverse impacts, consider ways to mitigate the consequences of a casing or casing/cement system loss-of-control/loss of containment event, while balancing potential unintended consequences related to the application of equipment like ESVs, SSVs, and SSSVs. Government and industry are already taking steps to implement risk based Integrity Management plans for natural gas underground storage.

The authors align with the recommendations made in PHMSA's Storage Advisory in Docket No. PHMSA – 2016-0016" with respect to decision-making around the use of ESV or alternatives. Specifically, the PHMSA advisory bullet #4 recommends periodic function tests for all ESV systems and the repair of deficiencies and failures, or the removal of the well from service, or employment of alternative and equivalently effective safety measures. PHMSA advisory bullet #5 recommends that operators evaluate the need for subsurface safety valves on new, removed, or replaced tubing strings or production casing using risk assessment aligning to API 1171 criteria as a minimum, and that where subsurface safety valves are not installed, the operator use the risk assessment to inform decisions on integrity inspection frequencies, reassessment intervals, and well integrity issue or incident mitigation criteria. The risk

assessment, decision, and rationale regarding application or potential application of an ESV system on a natural gas storage well (in a depleted hydrocarbon or aquifer reservoir) is a duty of a storage operator under the requirements of API 1171, Clause 6.2.5. The authors highlight the risk management process recommended to operators for use in the decision-making processes. Good decision making is transparent and assesses the outcomes of past decisions.

The authors recommend that storage operators engage in the following continual improvement actions:

- ✓ Follow the risk management process and minimum evaluation requirements in API 1171, Section 8, and clause 6.2.5, and share lessons learned and good practices through industry associations;
- ✓ Follow the additional guidance around risk management discussed in this Appendix and establish a consensus as to some uniform, minimum risk management process detail;
- ✓ Develop templates and methods to gather and share information regarding reliability of various well barrier element system components, including surface and subsurface ESV systems;
- ✓ Establish partnerships between operator groups and stakeholder groups to evaluate reliability of ESV systems and system components, with goals to establish, evaluate, and report safety performance and develop guidelines for good practices in integrity management and ESV system reliability management; and
- ✓ Collaborate through industry associations and regulatory agencies to develop common integrity management goals and establish regular forums where operating experiences can be shared and employee knowledge, skills, and experiences can be developed and enhanced.

Section 1. Overview

This Appendix was developed to assist with the understanding of emergency shutdown valve (ESV) systems, including type, typical application, usage, reliability, and determination of need based on site specific risk assessment. The data presented in this Appendix is a combination of available industry publications, recommended practices, standards, company experience and historical data.

An ESV system includes an actuated valve designed to close upon reaching previously defined operating threshold parameters. Common parameters include, but are not limited to, pressure, temperature, or flow rate. Valves can be actuated by mechanical, electrical, pneumatic, or gas-driven means. ESV systems can be located above or below the ground surface on gas storage wells. Below grade ESV systems can be further classified into shallow or deep set designs.

An ESV system typically consists of several components, including but not limited to:

1) Valve Control System (VCS) – Portion of an ESV system where logic is utilized to perform a specific action or set of actions upon reaching a pre-determined parameter (such as pressure, temperature, or flow rate thresholds). This system typically consists of a manifold, sensors, and a power source to control the valve. Hydraulic, electrical, mechanical, or other means are used to control the valve.
2) Valve – Typically a gate (flapper) or ball valve depending on its location within the well, wellhead tree, or adjacent to the wellhead. Based on the site specific characteristics of the well, the location of the valve could include:

a. Surface Controlled Surface Safety Valve (SCSV) – A valve placed above grade in the wellhead tree or adjacent to the wellhead which is controlled by a surface VCS.
b. Surface Controlled Subsurface Safety Valve (SCSSV) – A valve placed below grade in the well casing or tubing which is controlled by a surface VCS.
c. Subsurface Controlled Subsurface Safety Valve (SSCSV) – A valve placed below grade in a well casing or tubing which is controlled by a subsurface VCS.

3) Emergency Shutdown Valve System (ESV) – Components of an overall system including, but not limited to, a valve, the VCS, tubing or lines used to control the valve, flow couplings, or other downhole or surface assemblies used in the control and operation of the valve.

ESV systems are used in numerous applications, including offshore and gas storage environments. In offshore production wells, ESV systems are used below the mud line, or the sea floor, to control a well in the event of damage to the exposed part of the wellbore above the mud line from causes such as a hurricane, boat anchors, or other external event. Surface ESV systems are also used in cavern storage. API 1170, *Design and Operation of Solution-mined Salt Caverns Used for Natural Gas Storage*, requires the use of surface ESV systems in cavern storage wells. Both API 1171, *Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs,* and CSA Z341, *Storage of Hydrocarbons in Underground Formations*, require that a site specific risk assessment be performed for each well in reservoir storage to determine if an ESV system should be installed per the specific conditions at the location. Numerous other industry publications and standards recommend material, service, or maintenance guidelines for ESV systems.

An ESV system is a tool available to operators and is not intended to be a one size fits all solution. A gas storage well ESV can assist in controlling unrestricted flow from a well or wellhead for a specific set of conditions for which it is designed. But, based on available literature, a downhole ESV system reduces consequences of relatively few events since the likelihood of a loss of containment event occurring during normal operations is unlikely.

While an ESV can assist in controlling the unrestricted flow from a well or wellhead and thus serve a risk reduction role, literature sources and company experience suggest the application of ESV systems could add additional risk due to reliability issues with the components of the ESV system. Industry experience has established evidence of mean time to repair/mean time to failure and direct and secondary reliability issues related to flow interruptions, test failures, partial closures, and service capacity and reliability. The reliability issues cause an increased well re-entry (service) rate, which also carries a loss-of-containment risk.

Secondary methods can be employed to detect, respond to, and reduce a loss of control event into the tolerable risk range with or without an ESV system. Secondary methods include, but are not limited to: gas/flame detection monitoring equipment, annulus pressure monitoring, emergency plans for rapid response well kill or control, pressure test verification of containment barriers, pressure monitoring and control equipment, and, during workovers, regular blow-out preventer (BOP) testing and maintenance of dual barriers.

When evaluating the use of an ESV on a well, operators typically follow a defined decision making process, which includes:

1) Objectives clarification, where the operator defines the goals of their analysis by reviewing site specific conditions, operational characteristics, and environmental factors relevant to their operation.
2) Identify risk sources including hazards, threats, and potential hazardous situations. This analysis should also identify barriers to loss of containment events and identify gaps in the condition and effectiveness of barriers. Reliability issues with barriers could be common to other parts of the oil and gas industry and storage operators should consult technical literature sources.
3) Determine likelihood of well failure (loss of containment events) and potential impacts based on site specific conditions and incident duration.
4) Operators should follow a site-specific, risk-based assessment. After the assessments, operators prioritize wells by the risk estimated in the assessments and establish programs to prevent events by reducing the likelihood of the causes of gas containment failure and mitigating the consequences of a loss-of-containment event. This analysis should be performed on a well by well basis.

Consequence mitigation factors that tend to influence the decision to install an ESV system include proximity to places of habitation, roads, human gathering places, environmentally sensitive areas, other industrial infrastructure, including inter-related gas storage facilities, or other sensitive receptors. Event potential factors that could influence the decision to install ESV systems could include site-specific potential for impact due to natural forces (earth movements, seismic activity, floods, severe weather events, and other earth forces) or human-induced activity that could lead to forces adverse to well integrity.

Operators can develop risk management plans that might include ESV systems for wells defined in the integrity assessments as located within a significant impact radius potential of receptors or potentially subject to uncontrollable events from human or natural forces; the risk assessment and risk management plan should focus particularly on wells with capacity to flow at high rates and/or long durations.

Section 2. Description of ESV Systems

Locations of ESVs

Emergency Shutdown Valves can be located above ground (surface safety valves (SSV)) or below ground (subsurface safety valves (SSSV)). Operators choose the appropriate locations and configurations to meet their specific needs. API 14B, *Design, Installation, Repair and Operation Subsurface Safety Valve Systems,* provides definitions for safety valve systems, types, and components (API 14B - 3.20 SSSV system equipment; 3.21 surface-controlled subsurface safety valve SCSSV; 3.22 subsurface-controlled subsurface safety valve SSCSV; 3.23 subsurface safety valve SSSV; 3.24 surface control system; 3.25 surface safety valve SSV).

2.1 Surface Safety Valves

The SSV is part of a safety system to isolate the wellhead from the associated surface piping. This system consists of an isolation valve (typically a gate valve), a valve actuator/operator, and a valve control system (VCS). As this system is entirely above ground, all components are easily accessible for verification, testing and maintenance. Under normal operation, the VCS holds the SSV open. If the VCS detects an operational anomaly at the wellhead, such as excessive pressure or temperature, it allows the actuator to close the SSV.

2.2 Subsurface Safety Valves (SSSV)

The SSSV is a part of a flow shutdown system installed within a well to prevent uncontrolled flow. The SSSV can be in-line with the production tubing (tubing-retrievable) or be installed within the production casing (wireline-retrievable). There are several different SSSV configurations, each with their own advantages and disadvantages. The characteristics that differentiate the configurations of SSSVs are the locations of the valves (shallow-set vs. deep-set) and locations of the VCS (surface controlled vs. subsurface controlled).

Operators make decisions on the use and subsurface location of the SSSV based on a risk assessment balancing the risk reduction benefits of consequence mitigation and protection of potential receptors with the risk increase related to reliability of the SSSV, as described in more detail in following sections. The SSSV setting depth is a function of what the operator is trying to protect and the potential consequences the operator is trying to reduce. An operator could consider installing a shallow-set SSSV if the most significant threats relate to wellhead or surface network failure; an operator could consider installing a deep-set SSSV if there could be increased risk of casing or tubing failure deeper in the well.

Increasing the depth of the SSSV installation increases the technical difficulty and reliability related to surface-controlled systems and can also decrease flow capacity and reliability in many wells. Subsurface-controlled valves require set-points of flow rate/flow velocity or pressure differential in order to activate, which means that the subsurface-controlled valve will not activate until these conditions occur and there will be leaks of some magnitude for which the valve will not close. The working inventory pressure range and flow rate and velocity range of many storage wells complicates the set-point design and applicability of subsurface-controlled valves.

Deeper-set surface-controlled SSSV reliability issues are related to adverse mechanical operability impacts that can result from changes in flow or solids and liquids in the flow stream. The SSSV valve closure mechanism can be fouled or deteriorated by collection of organic and/or inorganic solids, erosion or corrosion of mechanical elements, or scouring, any of which can reduce functional performance and reliability. The effectiveness of the surface control system depends on the integrity of the hydraulic VCS control line and the control fluid, both of which are reduced due to the complications related to increased depth. (API 14B defines “control line” as the conduit utilized to transmit control signals to the surface-controlled subsurface safety valve. The “surface control system” is the surface equipment including manifolding, sensors, and power source to control the subsurface valve). Deeper-set surface-controlled SSSV systems have higher rates of reliability issues because the system itself is “bigger,” deeper, and therefore exposed to more hazards than shallower-set systems – as an

example, depth limits exist due to inability to overcome fluid mechanics and pressure drop in small-diameter control line tubing. Literature reviews summarized in Appendix 2 document lower reliability rates for deep-set systems.

2.2.1 Surface-Controlled Subsurface Safety Valve (SCSSV)

A Surface-Controlled Subsurface Safety Valve has its VCS above ground. Typically, the control system controls the SSSV with a hydraulic pressure line. If the control system senses an upset or becomes unresponsive, the SSSV internal spring closes the valve.

2.2.2 Subsurface-Controlled Subsurface Safety Valve (SSCSV)

A subsurface-controlled subsurface safety valve is a self-controlling valve. It is configured to close based on the differential pressure through the valve (where differential pressure can be associated with gas flow/velocity) or by pressure in the tubing (pressure type).

2.2.3 Subsurface Safety Valves Deep-Set

A deep-set SSSV (see Figure 1) is installed near the bottom of the well, generally thousands of feet below the surface.

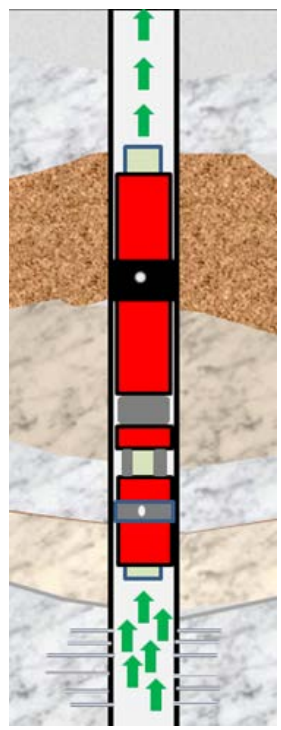


Figure 1: ***Subsurface Safety Valves Deep-Set***

2.2.4 Subsurface Safety Valves Shallow-set

A shallow-set SSSV is installed below the wellhead but near ground level. Typical depth below ground level for a shallow-set SSSV range is within 200 feet of the wellhead.

Section 3. Application and Experience with ESV in Underground Natural Gas Storage

The following discussion examines the benefits and potential risks of SSSV.

Brief history

SSSVs are typically installed in offshore oil and gas production wells where there is a chance the wellhead can be broken off above the sea floor due to mudslides, dragging ship anchors, and tropical storms damaging drilling or production platforms or vessels. The subsurface valves are typically installed in the production tubing upon completion of the well, ~100 feet below the mud line.

Onshore, several North American natural gas storage companies installed SSSVs in a subset of the former production wells when the depleted reservoirs were converted to gas storage. These shut-off valves were generally installed less than 200' below the surface in the depleted reservoir wells and in a few aquifer storage wells near residential communities or high traffic roads. The valves are designed to fail closed upon loss of hydraulic pressure supplied by the VCS.

Natural gas storage operators carefully evaluate new installations of SSSV. As described in the operator testimonials located in Appendix 1, there are potential benefits from installing SSSVs but there are also operational impacts and a number of risks associated with the installation and operation of SSSV.

Benefits of SSSVs/DHSVs

SSSVs can be an effective means of significantly reducing the gas flow from a well if the wellhead is catastrophically damaged or severed or if a large leak occurs in the casing or tubing above the setting depth of the valve. As discussed in Section 2.2.3 and 2.2.4, an SSSV can be installed as a deep-set or shallow-set valve within well tubing, just below the wellhead, and/or in the casing above the casing perforations, several thousand feet below the wellhead. In a shallow-set installation, generally within 200 feet below the wellhead, the SSSV closes in the event the wellhead is extensively damaged or a tubing leak develops below the wellhead and above the SSSV. For the deep-set location (near the bottom of the well), the SSSV paired with a packer and a full tubing string could potentially isolate the entire tubing string if the wellhead is damaged or the tubing develops a leak. As most deep-set SSSVs are hydraulically controlled by a VCS, the maximum depth is often limited by the allowable hydraulic pressure at the SSSV.

The SSSV and the SSV are intended to function as consequence mitigation barriers, closing down flow from a well in the event of a large, even catastrophic leak. An "event" of significant magnitude or force must occur in order for the valve to activate; the event must cause a loss of control pressure or a substantial pressure, flow, or velocity change. Whereas casing and cement around the casing function as "passive" technical (physical) barriers to contain the gas at all times and with no special effort, ESV systems are technical control barriers that function only in the case of a triggering event. The distinction in barrier category is critical in order to understand that the functional purpose, reliability, and set point location of the ESV system limit its risk reduction capability to only those scenarios in which the ESV system would activate. However, since wells have limited means of shut-off in the event of a leak, ESV systems provide a means to perform a self-activated closure and thus ESV have risk reduction value in selected situations where flow from a well would be at high rate for an extended period and not be controllable within reasonably short time periods through other means. API 1171 requires that storage

operators evaluate the risk reduction value of ESV systems in each well and use the risk assessment to decide on use of an ESV system in any particular well.

While the operator testimonials in Appendix 1 represent well over 5,000 well-years of operation with SSSV, it is difficult to find cases where operators cite instances where the SSSV functioned in response to a legitimate triggering event.

Operational Impacts of deploying SSSV in Depleted Reservoirs and Aquifers

Per Section 2.2, there are two typical SSSV installation types and they have different impacts on operations. The first installation type is a tubing-conveyed SSSV installed in a tubing string, generally with a very similar cross-sectional flow area as the tubing. The second is a wireline-conveyed SSSV installed in the flow tubular, which sets the entire assembly inside the flow tubing and therefore has a smaller cross-sectional flow area than the tubing. The tubing-conveyed and the wireline-conveyed systems can be installed at various depths, although if the operation of the valve is surface-controlled, the depth of setting is influenced by the design and reliability of the control line and control fluid. Well operating pressure, flow fluid composition, flow tubing size, and other factors, in addition to the control line and control fluid, influence the setting depth restrictions for a Surface Controlled Subsurface Safety Valve (SCSSV). Natural gas storage operators, when using SCSSV, generally have installed the valves at shallow depths.

New wells planned with SSSVs and tubing have customized wellheads designed to support the connections and the weight of the tubing and the SSSV. The new wellheads contain fittings with bowls designed to suspend and secure the tubing hanger. Existing wells must be taken out-of-service to install tubing and SSSVs. Installing an SSSV on tubing in an existing well requires many steps to modify and add the connections necessary to support tubing and SSSV controls to the existing wellhead. Generally a new wellhead is required after obtaining the location-specific design. The existing wellhead must be removed and modified or replaced. Before removing the wellhead the well must be shut down and controlled ("killed") to render it safe, then heavy equipment (a rig and related equipment rated for the forces expected during the well intervention/service work) is brought in to disassemble and remove the wellhead and install a blowout preventer ("BOP"). Tubing and SSSV assembly (with control lines) are installed in the well and the tubing is hung in the new wellhead assembly, which includes a tubing hanger and tubing valve. Note that this new tubing valve becomes the master valve controlling flow from the well when the flow is coming from the tubing only. Once the downhole installation is complete and pressure tested, the surface control system is connected and tested to ensure functioning of the SSSV in accordance with standards and specifications.

From that point forward, the SSSV and its controls will be tested annually, or more frequently if conditions warrant, to ensure proper operation. The well must be taken out-of-service during SSSV system removal, installation, testing, intervention, modification and repair and/or wellhead modifications related to the SSSV system. Natural gas storage operators must make risk-based decisions with respect to taking a well out of service if an SSSV fails a function test; the decisions are predicated on the values of safety, environmental stewardship, and storage service reliability.

Installing tubing and an SSSV within the well reduces the cross-sectional flowing area by approximately 50 percent, depending on the size of the tubing - if the tubing is half the diameter of the casing, the flowing area is reduced ~75 percent. The reduction in flowing area causes a pressure drop which could

reduce deliverability during critical periods from a negligible range to more than 50 percent, depending on the well flow capability and operating pressure range. If the flow deliverability requirements remain the same for a gas storage field, then new gas storage wells must be drilled to make up for the lost capacity. Each storage well operator must carefully evaluate the deliverability impact of tubing and SSSVs to ensure their fields can deliver the gas to serve market demand, including residential heating and power needs on a peak or cold, high-demand winter day, as well as on the last day of withdrawal, when storage field pressures are much less at the low end of seasonal inventory.

An SSSV installed in the tubing string adds operational challenges and safety considerations. The operator incurs additional risks to extricate the tubing and the SSSV from the well in order to perform the manufacturer-recommended maintenance to the valve or when the valve fails to properly operate or seal during testing. SSSV and tubing removal might require a snubbing unit, much larger equipment than the more typical wireline truck used to run tools, which increases risk to operating personnel charged with removing the valve when maintenance is required.

Casing mounted SSSVs are typically installed using wireline. In both cases the valve itself restricts the flow path, which can cause pressure loss which reduces deliverability, contributes to a buildup of paraffin or inorganic scales, increases maintenance demands for valve service, and causes unnecessary shut-ins when the valve closes prematurely or fails open, closed or partially closed.

Additional Risk Introduced by SSSVs

The risks introduced to a well associated with SSSV include the installation, malfunction and failure of the SSSV components. Adding SSSVs to existing wells requires shutting in the well, killing the well - usually by installing plugs and adding water to control well pressure - replacing the wellhead and installing the SSSV, often on a tubing/packer string. These steps, while manageable, expose the operator and environment to risks of uncontrolled releases. Well servicing exposes workers and nearby public to loss of energy in the event of well re-entry to remove and service a valve after an unintended closure or malfunction of the SSSV.

SSSVs can fail and/or function improperly due to a number of circumstances including but not limited to hydraulic leaks and contamination by solids, which impair the function of SV components. Surface controlled SSSVs have suffered from control failures, seal and tubing leaks and malfunctions which cause the valve to close. A tubing-retrievable SSSV is connected to the tubing and lowered in the well with a drilling or service rig. If a leak develops in the hydraulic control line or any of the seals, a drilling or service rig must be brought in to retrieve the SSSV from the well. Until a rig can be brought in, the well remains closed and unable to deliver gas. Every time the SSSV is removed from the well for replacement, repair, or servicing, some methane is vented to the atmosphere. While the gas loss quantity per installation is minimal, if SSSVs were required for all gas wells, then the gas loss volume would multiply by thousands. As SSSV have some well-established reliability ranges, the increased well interventions to pull the valve for well casing inspection or to service and repair the valve would increase methane emissions.

API 1171 recommends periodic inspection of the production casing integrity. Inspecting the casing involves the use of tools that make contact with the casing wall to detect the location, size, and shape of any defect that may be present. Many of the analytical tools available to perform detailed casing inspection require removal of the tubing, SSSV and packer isolating the tubing. Because SSSVs and

tubing are installed inside the well casing, they impede the entry and exit of analytical tools, such as well profile calipers, into and from the well. This impedes an operator's ability to proactively assess the integrity of the well via casing inspection and flow logging/detection programs. In order to maintain surveillance of the condition of the casing, casing inspection tools and flow detection devices can be run inside a "casing" completion, and follow-up surveys can be directed to various frequencies depending on the findings of a survey or depending on a combination of other factors that recommend for inspection. An SSSV/tubing string installation increases the cost and complexity of casing condition monitoring.

SSSVs do not arrest all leaks. A shallow SSSV installation does not shutdown the flow of gas through a deep casing breach occurring below the set point of the SSSV. Shallow SSSVs are only designed to limit the amount of escaping gas in a catastrophic surface event. The closure mechanisms might not actuate in the event of a steady but small leak that does not meet some threshold of pressure or flow differential or velocity.

SSSVs are not completely gas tight over time due to the normal yet relatively harsh operating conditions in many storage well situations. The sealing surfaces can be exposed to the flow of gas, water, and other components such as sand. A scratch of just a few thousandths of an inch may prevent a flapper or ball SSSV from achieving a complete seal. The SSSV can still be effective in minimizing gas loss in an extreme abnormal event. Specifications such as API 14B define an allowable leakage rate that must be carefully reviewed for practicality as it would not make sense to extract a SSSV hundreds to thousands of feet below the earth's surface for a trace leak that is only detectable during a test when the valve may be in very good condition and fully capable of arresting nearly all of the flow in a catastrophic surface issue.

SSSVs prevent the installation of a full size plug in the well, impeding resolution of a potentially hazardous situation or significant leak event. SSSVs, regardless of where they are installed, are only effective in limiting a leak that is located above the SSSV. However in the very unlikely event that a downhole leak occurs, the SSSV reduces the operator's ability to deliver an effective treatment because repair tools must be small enough to fit through the SSSV without getting caught in the length of the SSSV profile. Generally, for efficient well intervention and isolation in a leak event, restrictions inside the casing could and often do need removal. Deep set subsurface safety valves increase risk of problems and prevent the operator from setting a plug to control a well unless an additional packer is set beneath the point where the SSSV is set; such an arrangement retains a risk due to time and complexity for extraction of the tubing string and SSSV, relying on the lower packer plug to hold for a long period of time and hoping that no problems occur with the extraction or re-insertion.

Cost of SSSVs in Depleted Reservoirs and Aquifers

Two of the operator-authors of this Appendix developed independent estimates of installation and servicing costs related to ESV systems, particularly SSSV, and associated costs for a full tubing string on an isolation packer and wellhead accommodations; the operators also estimated the cost of drilling new wells and equipping those wells with SSSV on full tubing strings. The operators developing the estimates represent nearly 2000 natural gas storage wells and 40 gas storage reservoirs, a wide range of pressure, depth, flow potential and geographic location. The cost estimates of each operator's independent determination compared favorably and so the summary below represents the range found by both analyses.

There are five major costs associated with SSSVs: the cost of the valve, the cost of installation, the routine operations and maintenance (O&M) costs relating directly and indirectly to the presence of an SSSV system, the life cycle costs of the SSSV system itself including capital replacement costs, and the cost of additional facilities because of the loss in throughput and other risk and risk treatment interdependencies.

The direct cost of an SSSV depends on size, and typically ranges from $15,000 - $140,000. The total estimated installed cost for a SSSV/full tubing string and packer in a 7" production casing string is ~$250,000 per well, with a wide range - greater for deep wells and lower for shallow wells. Considering that there are approximately 12,000 to 14,000 gas storage wells in the United States without tubing/packer and SSSVs, the cost for installation in all wells would be on the order of $2 to $4 billion. Operations and maintenance costs could average $2,000 per well annually, for a range of $25 -$50 million for basic maintenance added across the gas storage industry. The life cycle cost could be significant based on reported reliability of the valves. Some wells may require workover or snubbing rigs and multiple valve replacements over a 100-year well lifetime at an estimated total industry cost of $10 billion, or roughly $100 million annually.

The cost for replacement of lost capacity resulting from the installation of tubing, packer, and the SSSV can be represented by the cost of drilling additional wells. New well drilling requirements depend on a number of factors and how those factors contribute to deliverability and/or service reliability impairment if SSSV on full tubing strings were installed; the impact factors include well depth, pressure, flow potential, and the significance to the amount of cross-sectional flow area restriction along a length of the well. The new well drilling analysis assumed that horizontal drilling techniques would be used to provide the service restoration. The analysis yielded an estimate in the range of 1,000 to 5,000 new wells that could be required to replace the lost deliverability resulting from installation of SSSV on tubing. The well replacement cost range is estimated to be between $2 and $10 billion.

SSSVs in Salt Cavern Storage Wells

Salt cavern gas storage facilities have been developed for gas storage. These underground facilities tend to be 1970s-2010 vintage facilities and were developed using new drilling and well completion techniques, utilizing multiple concentric large diameter casings, ranging from 16 inches up to 42 inches, whereas the traditional production wells are less than 10 inches in diameter. The cavern wells have a minimum of two barriers into the salt. Wellhead shut-off valves are installed on every well. Emergency Shutdown Valves (Surface Valves) are required by API 1170 and CSA Z341.2. Surface valves enable the operator to isolate both the gas well and the gathering piping system. Because SSVs are above ground, they are easier to inspect and maintain as compared to subsurface valve systems. The stroke and operation of the valve can be observed directly by the technician and adjustments can be made when deemed necessary. Service ports and grease fittings are readily accessible and can be serviced annually with minimum effort or special tools.

Comparison and Contrast of SSSV and a SSV

Both SSSV and SSV are comprised of multiple components to ensure that they fail closed when needed. As depicted in Figure 2, the SSSV offers a narrow flow path (light green) whereas the SSV ball valve shown to the right is full opening (steel ball port is the same size as the piping) causing virtually no

restriction. The SSSV must be removed to be serviced. Above ground valves can be readily serviced, in many cases without impeding the flow of gas.

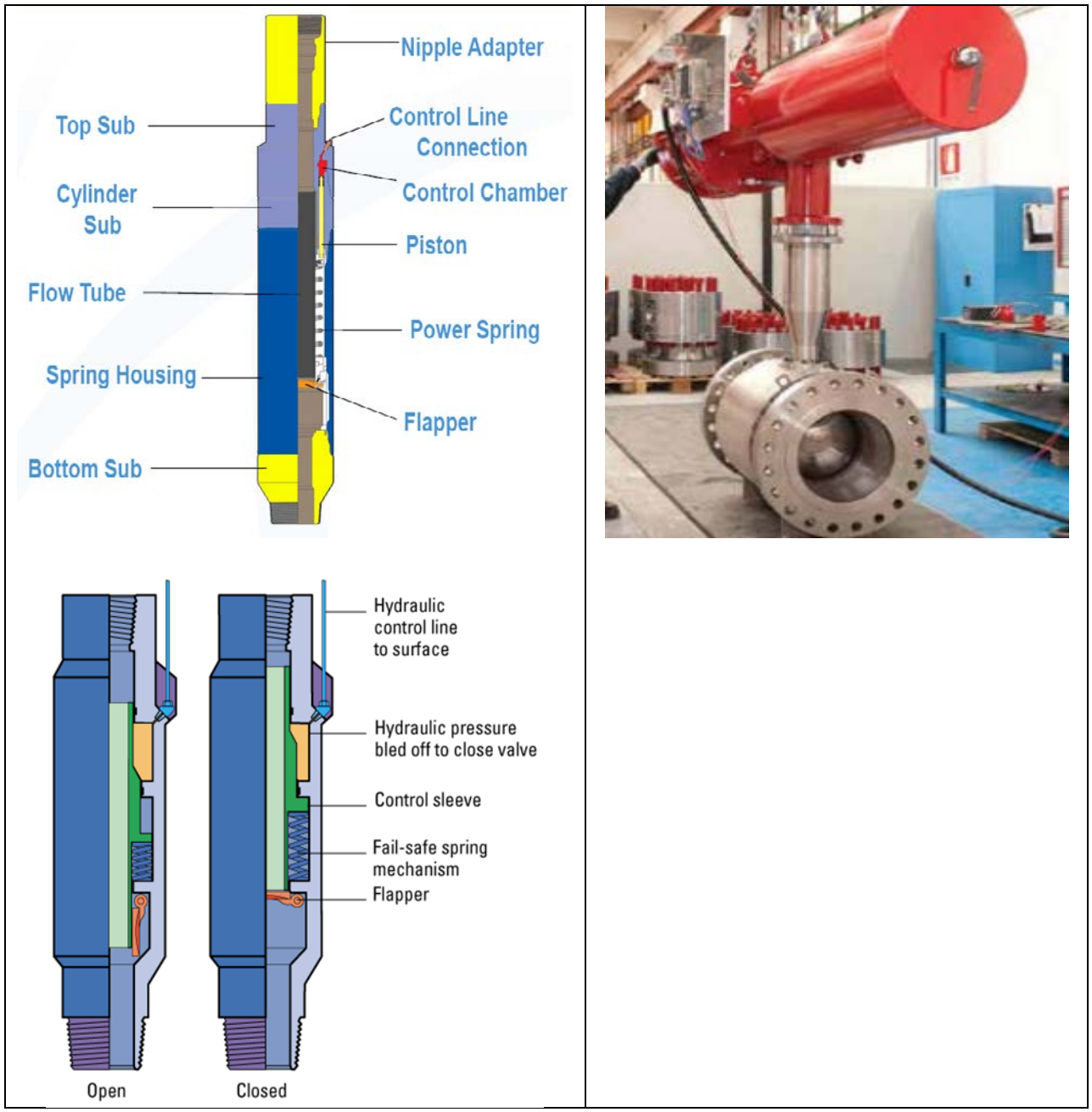


Figure 2. (Left, top and bottom) Subsurface Safety Valve profile (flapper type), and (right) Surface Safety Valve (ball valve type). (Figures courtesy of Baker Hughes)

ESV Reliability - Company Operating Experience

Five storage operators shared their experiences of operating wells with various ESV systems. The dataset from these five operators represents nearly 200,000 well-years of total storage well operation, and over 5,000 well-years of ESV system operation, most of it downhole safety valve system operation.

Appendix 1 contains each operator's more detailed discussion of the experience, the risk assessment used, the reliability and safety issues involved, and the performance impact of subsurface safety valves in particular.

The storage operators represented in Appendix 1 provide some quantitative reliability information: safety valve function test and operating failure rates are in the 0.01-0.03 failures per well-year range – note that this failure rate is inclusive of all causes of failure, not just the mechanical failure of the valve mechanism itself.

Re-entry-and-removal/replacement rates for subsurface safety valves are in the range of 0.1-0.2 entries per well-year, a rate that is composed of entries for SV inspection and repair, entries for test/function failures, and entries for casing inspection.

Flow and function reliability issues related to downhole safety valves include hydrates, salt, or paraffin bridging in the safety valve assembly, or function test failures due to the same types of bridging agents fouling the flapper closure mechanisms. The corrective maintenance issue, or reliability issue, rates are in the range of 0.15 per well-year of operation. However, the annual corrective maintenance rate varies with storage field/well use and winter severity. Corrective maintenance actions include flushing with solvents such as water, methanol, or heated diesel oil, and in many instances these are successful in restoring flow and proper valve function.

Some storage operators report substantial flow restrictions due to subsurface safety valve installation. High deliverability well flow can be adversely impacted by restrictions in flow diameter along the length of the tubing string on which the safety valve is run. The decrease in flow due to the tubing and subsurface safety valve system could cause the operator to drill more wells to replace lost service reliability. Additional tubing, packer, and safety valve systems could increase the number of well re-entries due to known reliability rates related to mean time to repair/mean time to failure for tubing, packer, safety valves and additional wellhead components.

Storage well applications of ESV and related equipment, loss of containment rates, well component failure rates and inter-dependent risk

In 2011, a survey of ESV systems in non-cavern storage wells solicited storage operators to provide voluntary responses to a number of questions, including whether the operator used any type of ESV system (surface or subsurface) on any wells in their storage assets, the criteria used for decision-making on application of ESV systems, and whether the operator was evaluating use of ESV systems of any type in the future.

The survey yielded responses from 22 storage operators representing more than 8,500 wells, or about half of all storage wells in North America. Approximately 30 percent of the operators did not use any ESV system in their wells, but approximately 11 percent of all wells represented in responses had some

type of ESV system and some wells had both surface and subsurface systems. Overall, only four percent of wells represented in the survey had subsurface safety valve systems.

The reasons for ESV system use included well flow potential in ~27 percent of cases, well pressure in 18 percent of cases, proximity to receptors in 27percent of cases, loss prevention in 27 percent of cases, and other or no reason given in 23 percent of cases (some respondents cited multiple reasons thus the percentages do not total 100 percent). Only two of 22 respondents indicated they were considering additional ESV system installations and were using risk assessment to make the decisions.

In addition to the storage operator shared information, Appendix 2 contains summaries of several Society of Petroleum Engineers papers regarding reliability of safety valve systems.

The authors also referred to the March 2005 report to the Gas Research Institute under Contract No. 8604, Project No. 809833, "Risk Assessment Methodology For Accidental Natural Gas and Highly Volatile Liquid Releases From Underground Storage, Near-Well Equipment," prepared by Glenn DeWolf, Katherine Searcy, Douglas Orr, and Christopher Loughran on behalf of URS Corporation.

The discussion of ESV systems and their applicability and reliability necessarily involves a discussion of the reliability of the entire well system and the inter-dependent nature of physical components and human interactions in the analysis of risk. Loss of containment rates and reliability rates obtained from the compilation of sources is summarized in Table 2 and contains a summary of well and selected well component failure rates. Reliability rates for tubing/packer systems and wellhead systems are included in Table 2 along with casing, cement, and loss-of-containment during drilling or service intervention ("workover") since all components and work types represent failure paths leading to potential loss of containment events.

Table 2. Summary of Well and Selected Well Component Failure Rates, Reliability Rates, and Impact Analysis

case	min	max	mean	source
loss of containment, drlg - "known areas", per well	0.0002	0.0003	0.00025	compilation, industry data
loss of containment, workover, per well	0.00007	0.0004	0.000235	compilation, industry data
loss of containment, re-entries, per re-entry	0.0000891	0.000341	0.000215	URS (2005)
loss of containment, re-entries, per re-entry			0.000680	Durham and Pavely (SPE #56934)
tbg/csg fail, per well-yr			0.0000034	Busch, Policky, Llewellyn (1985)
tbg fail, per well-yr			0.002	Busch, Policky, Llewellyn (1985)
wh fail, per well-yr			0.000012	Busch, Policky, Llewellyn (1985)
cement - failure per well-yr			0.000064	URS (2005)
casing (no cement) - failure per well-yr	0.000016	0.000029	0.000023	URS (2005)
csg fail (2 or 2+ barrier - csg, cmt, etc), well-yr		0.000015	0.000007	one storage operator testimonial
well fail with shallow set SCSSV - per well-yr			0.000049	URS (2005)
well fail with shallow set SCSSV - per well-yr	0.00006	0.00008		Moines and Iversen (1990) OTC #6462
Surface SV fail, per demand			0.000000071	URS (2005)
Subsurface SV failure, per demand	0.000004	0.000020		URS (2005)
SSSV functional failure/repair per well-yr	0.01	0.03		Storage operator experience

SSSV functional failure.repair per well-yr	0.02	0.03		Durham and Pavely (SPE #56934)
SSSV functional failure/repair per well-yr			0.027	Moines and Strand (SPE #63112) - 1999 MTTF
tubing-packer systems - repair/re-entry per well-yr			0.032	one storage operator testimonial

The authors of this Appendix estimated the current storage industry usage rates of ESV systems and tubing/packer systems based on the industry surveys referenced above and informal discussions and personal communications. The first few lines of Table 3 show the estimate that three to five percent of natural gas storage wells have SSSV and 10-25 percent of natural gas storage wells have a full tubing string set into an isolation packer.

The authors estimated the impact to service reliability and well service intervention rates if the use of SSSV and tubing/packer systems were applied to all natural gas storage wells, in order to demonstrate the inter-dependent nature of well component reliability and well intervention risk. The authors estimate that the widespread installation of tubing/packer and SSSV would result in a service reliability replacement demand that could result in a five to 25 percent increase in the number of storage wells. The total impact of all SSSV and tubing/packer installations is summarized for both existing wells and potential new well additions to show that there would be a likely impact to more than 16,000 storage wells. The remaining rows of Table 3 show the authors' estimates of failure rates of the components and failure rates due to well servicing loss of containment. The risk of loss of containment is increased by the count rate addition due to installation multiplied by the re-entry rate due to component failure, multiplied by the loss-of-containment rates during well intervention.

Table 3. Impact Estimate		min	max
Number of storage wells, approximate (AGA Underground Storage Survey 2013)	17600		
Estimated percentage with SSSV (Author estimates)	4	3	5
Estimated wells with SSSV (Author estimates)	704	528	880
Estimated percentage with tubing-packer systems (Author estimates)	13	10	25
Estimated wells with tubing-packer systems (Author estimates)	2288	1760	4400
Estimated percent well additions for tubing restrictions to restore and maintain deliverability and capacity (Author analysis estimate)	10	5	25
Estimated well additions (percentage in line above converted to a number) (Author analysis estimate)	1760	880	4400
Added SSSV and tubing/packer systems (if "all wells must") (Author analysis)	14608	15312	12320
Including new wells (if "all wells must") (Author analysis)	16368	16192	16720
Minimum re-entry rate per well-yr SSSV+tbg/pkr system MTTR (Author estimates and company testimony)	0.037		
Increased re-entries, minimum estimate, per year (min) (Author estimates)	606	599	619
Maximum re-entry rate per well-yr SSSV+tbg/pkr system MTTR (Author estimates)	0.062		
Increased re-entries, maximum estimate, per year (max) (Author estimates)	1015	1004	1037

Loss of control, well re-entry (high value,Durham/Pavely)	0.00068		
number of wells re-entered for MTTR (max) (Author estimates)		1037	
expected number of loss of control incidents, per year, for wells re-entered for SSSV/tbg reliability (HIGH VALUE) (Author analysis/estimate)			0.705
Loss of control, well re-entry (low value, URS)	0.000215		
number of wells re-entered for MTTR (max) (Author estimate)		599	
expected number of loss of control incidents, per year, for wells re-entered for SSSV/tbg reliability (LOW VALUE) (Author estimate)			0.129

The authors summarize from Tables 2 and 3 that while SSSV systems can decrease risk in a loss of containment event, a greater application of subsurface well components and the inter-dependencies of equipment reliability rates and well intervention loss of containment rates would nullify the risk-reduction benefits of SSSV and could increase the risk of loss of containment.

Section 4. Standards and regulations applicable to the use of ESV

The natural gas storage industry integrity management in North America is guided by several standards. API 1170 - Design and Operation of Solution-mined Salt Caverns Used for Natural Gas Storage, and API 1171 - Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs, were published in 2015.

API 1171, in Clause 6.2.5, specifies that operators evaluate the need for an emergency shutdown valve in wells using as a minimum set of variables: distance from dwellings, potential dwellings, or outside areas where people frequent or congregate, fluid composition and maximum flow potential, distance from wellheads and other surface equipment, site access availability for remedial and emergency equipment, proximity to public transportation or industrial facilities, the current and future/expected state of development in the area, regional topography, drainage, and environmental considerations, and the added risk created by installation and servicing requirements relative to the ESV system and alternative protection/mitigation measures.

API 1171 specifies minimum annual shutdown valve system function testing and requires that a closed ESV system be manually reopened at the site of the valve after an inspection and not opened from a remote location.

API 1170 has a number of requirements for surface emergency shut down valves (ESD). Clause 8.4.1 of API 1170 requires ESD equipment during cavern development when solution mining under gas, re-watering, or de-brining. All flow courses from the wellhead to the production lines are required to have ESD, and the ESD should be connected to the SCADA system for control and monitoring (Clause 8.5.2). The ESD valve must be installed at or near the wing valve off the wellhead (Clause 9.2.2). Finally, Clause 9.4.4 covers periodic testing recommendations, which includes tests of all components of the system.

In Canada, the Canadian Standards Association (CSA) Z341 series apply (Storage of hydrocarbons in underground formations). In CSA Z341.1-14, Reservoir storage, an ESD valve is required if the operator determines the need as a result of a risk assessment (as per Clause 7.1) or if very close to a building designed for occupancy. The applicable radius of impact equation makes a simple relationship of

pressure and well casing diameter to the radial distance from the building (see Clause 9.3.2.1). The radius-pressure-casing size relationship is based on an assumption of worst case well flow capacity, ignition of the gas, and a heat flux of 5.0 kW/m2 representing a 30-second burn threshold, as per the Gas Research Institute project GRI-00/0189.

API 1171 and CSA Z341.1 are very similar in the risk assessment consequence criteria; Z341.1 requires evaluation, in addition to proximity to potentially occupied buildings, of proximity to adjacent wells and other surface developments, the number of wells connected in common to surface pipe networks, the reaction time of the operator to shut in wells, and the storage capacity of the facility.

CSA Z341.1 requires that when an ESV system is used a valve must be installed on each flowline to the wellhead and as close as possible to the wellhead, pressure rated to maximum operating pressure of the well-pipe system, fail-closed and capable of position monitoring, remote and local operation, and automatic activation. If a subsurface safety valve is installed, it must be function tested twice per year and repaired or replaced if the function test fails. Greater function test frequency is recommended when operating conditions include corrosive agents, fouling/depositing/scaling agents, or the valve experiences large variations in temperature and pressure. Z341.1 also requires testing of the ESV control system once per year, including instrumentation, valving, shutdowns, wiring connections, and circuit integrity and closure times (Clause 10.2.2).

CSA Z341.2-14, Salt cavern storage, is similar to API 1170 in its requirements for salt cavern well ESV systems. Clause 9.3 has the same location and operability requirements as in Z341.1, but adds that closure times should be set to minimize hammering and that activation can occur by over-pressuring or under-pressuring of the hydrocarbon system, over-pressuring of the brine system, and high hydrocarbon temperature.

Material, Installation, and Service Specifications

API 14A (ISO 10432), Specification for Subsurface Safety Valve Equipment, provides functional applications compatibility, technical specifications for design, materials and manufacturing requirements, repair and redress, and shipping, storing and handling. The 14A Annexes cover testing, validation, and verification requirements.

API 14B (ISO 10417), Design, Installation, Repair and Operation of Subsurface Safety Valve Systems, covers system configuration, equipment, documentation and data control. The Annexes cover redress, installation, operations, sizing of the system, testing, and failure reporting. API 14B covers acceptable leak rates when performing function tests.

API 14C addresses surface safety systems on offshore production platforms.

API 6AV2 superseded API 14H and treats surface safety valves and underwater safety valves.

General Well Integrity / Integrity Management Systems

ISO 16530-1, Petroleum and natural gas industries — Well integrity —Part 1: Life cycle governance, was published in 2015. ISO 16530-1 identifies an SSSV as a possible well barrier (Clause 4.7.3.4). ESD/SSV should be tested in accordance with API 6AV2 (Clause 4.9.2.2).

ISO advocates definition of Safety Critical Elements (SCE); all parts of an ESD system are to be considered SCE (Clause 6.4.5) and increased maintenance frequency is recommended, along with documentation. In ISO 16530-2, Clause 15.4.2, notes that higher frequencies of function testing of SSSV can reduce problems found when verification testing is performed.

Operating limits and verification tests are to be operator-defined; Clause 5.6.2 includes considerations for SCSSV such as setting depth, control line actuation pressure, and well conditions.

ISO 16530 Appendix F provides a description of surface and subsurface safety valves (ESD), their function, and possible failure modes. A surface safety valve, the function of which is to provide shutdown and isolation of the well to production process/flow lines, can fail due to malfunction, mechanical damage, control line pressure problems, incomplete closure or unacceptable leakage. For a surface controlled subsurface safety valve, the function can fail due to lost communication with the control line, leakage above acceptance criteria, failure to close on demand or in an acceptable amount of time, mechanical damage, or other malfunctions. ISO cites the API 14B threshold acceptable leak rate as 15 SCF/min for gas (approximately ~22 Mscf/d).

Regulations

The authors are not aware of any state oil and gas regulations that require the use of downhole safety valves in onshore wells. Surface safety systems, including emergency shut down valves, are required in cavern storage operations in a number of states. In the US and Canada, cavern storage operations need surface safety systems, including emergency shutdown valves, and the requirement is embodied in the industry recommended practices of API 1170 and CSA Z341.2.

The Bureau of Safety and Environmental Enforcement (BSEE) regulations (Title 30, Chapter II, Subchapter B, Part 250, Subpart H , §250.801) require offshore production wells capable of flow to have downhole safety valves and platform safety systems, including emergency shut down systems.

- 250.801 (c) stipulates a preference for surface-controlled subsurface safety valves installed in a tubing string and requires that such a valve be installed when the tubing is next serviced.
- The depth of the valve must be at least 100’ below the mud line.
- The need for a safety device in offshore wells is due to lack of accessibility to the well and the hazards of the offshore environment. Where a subsurface safety valve is not installed, the well shall be attended “…in the immediate vicinity…”

BSEE 250.802-250.808 addresses surface safety systems, which must be installed on all production facilities offshore. The regulations address design, installation, testing, quality requirements for closure times and leak rates, and other related performance factors, including personnel competence, training, and attentiveness to the safety systems.

In summary, regulations requiring emergency systems inclusive of surface or subsurface safety valves exist today in settings where risk of loss of containment is elevated due to:

- High consequences of failure, including rates of flow and radius of impact, fire potential, and escape capability of workers or the public;

- Discharge into water, air, or land is difficult to confine and contain within a limited space;
- Accessibility and timeliness of human intervention emergency response services is hampered due to well location;
- Impact to other infrastructure could create cascading events; and
- Hazards are difficult to anticipate and manage, and such hazards might include forces of nature, high pressure, high temperature, flow stream composition, rate, and extended volume potential, and duration of a loss of containment after a loss of containment event occurs.

Section 5. Risk management and decision-making

Section 8 of API 1171 requires that operators develop risk management processes with risk source identification, risk analysis, evaluation of risk and the ability to control risk by implementing risk treatments such as preventive, mitigative, and monitoring programs or well remediation. API 1171 requires that storage operators perform periodic review and reassessment of the risk management process.

API 1171 requires operators to assess the risk of gas containment failure due to a number of causes including inadequate mechanical isolation caused by time-independent design features, construction/as-built features, material defects, material deficiencies and misapplications (inappropriate casing joint thread design, for example), or time-dependent decay of barriers due to corrosion, erosion, cement/cement bond degradation or disbondment, valve failure, gasket failure, etc.; loss of control while drilling, completing, or service interventions; third party actions; natural forces of earth systems – weather, ground movements, floods, etc.; and other causes.

Operators are advised to rank and prioritize risk and establish programs that prevent events by reducing the likelihood of the causes of gas containment failure and mitigate the consequences of a loss-of-containment event.

Throughout API 1171, operators are advised to use risk assessments to inform decision-making related to many integrity management practices.

CSA Z341.1 requires risk assessment (Clause 7.1) and provides guidelines for risk assessment in Appendix B. Similar to API 1171, CSA Appendix B emphasizes the use of risk assessment in decision-making regarding design, well construction and completion, location, operations, maintenance, monitoring, plugging, and site restoration.

ISO 16530-1 provides guidance on relating well integrity program task frequency to the risk identified in the operator's risk assessment.

Objectives and Contexts

The risk management process is a decision-making process. The first step requires clarification of objectives set into the external contexts of the operator's environment and the internal context of each operator's company.

The primary objectives of each and every storage operator are 1) protecting human life, both of the public at large, locally in immediate areas of impact, and workers engaged in operations and support operations, 2) providing reliable service, 3) stewardship of the environment, and 4) the protection of property and financial resources. This four-fold aspect sets the fundamental, values-driven part of the gas storage operations objectives.

The operator defines the internal and external contexts of their storage operations and site specific contexts, the risk analysis method to use and the decision criteria.

Risk Source Identification

Operators identify the sources of risk – hazards, threats, and hazardous situations – that could affect the storage wells; then the operators identify the barriers and controls in place that prevent the risk sources from activating into events or that mitigate the consequences of events. Tables 1 and 2 in Section 8 of API 1171 provide a template of hazards and barriers/controls for operators to use when assessing site specific and company-specific risk sources and risk control programs.

Risk Analysis

Risk analysis estimates the likelihood of well failure and the likelihood-severity range of consequential impact.

The literature survey summarized in Appendix 2 provides ranges of well component failure modes and rates with and without ESV systems. Fault tree analyses in several studies have indicated up to an order of magnitude reduction in failure with subsurface safety valves installed, although when adding in the workover rates due to safety valve reliability, the overall rates of loss of containment with and without safety valves can be in the same order of magnitude.

The historical rate of significant well failures during operation is in the E-05 per well-year range, while loss-of-containment during well interventions is in the E-04 to E-05 range (per well entry). While the use of safety valves in the downhole environment can reduce likelihood of some failures if they occur uphole or downstream from the safety valve location, the failure rates with and without safety valves are in ranges described qualitatively as very unlikely (E-04 to E-05, as defined for hazardous process facilities by the Center for Chemical Process Safety (CCPS), American Institute of Chemical Engineers (AIChE); CCPS order of magnitude event frequencies align to qualitative descriptors: “extremely unlikely to remote” is <1E-05, “very unlikely” is in a range 1E-05 to 0.99E-03, “unlikely” is in a range 0.99E-03 to 0.99E-02, and “likely” is >1E-02).

The failure likelihood for which a subsurface safety valve is designed to protect against is “very unlikely,” so that when the consequence potential also is small, the estimated risk without a subsurface safety valve almost surely will be acceptable, or tolerable with risk controls other than subsurface safety valves.

A storage operator can evaluate the likelihood for a well to have a loss-of-containment event on the basis of the well’s as-built condition, including the number and quality of barriers such as casing, cement, or shut-off devices; on condition assessments of those barriers against operating conditions (casing integrity logs and the recency of the information, cement integrity logs, annulus pressure

observations, pressure tests, function tests); maintenance, monitoring, and inspection of primary barriers and well conditions; and frequency and reasons to enter (intervene in) the well.

In events where safety, environment, and service reliability could be threatened, operators often take a precautionary approach – which says that when the chance of something happening is increasingly remote but the severity of the impact is potentially large, a cautious approach should be taken. The precautionary approach can be invoked when there is a need to focus the risk analysis on the consequence potential because of the number, density, and/or critical importance of potential receptors. Operators can identify receptors in a potential impact area and estimate the potential impacts those receptors could experience should a loss of containment event occur at a well. Operators can assess conditions which affect the likelihood of failure events and their escalation: the as-built condition of the well, the number of containment barriers and their state of integrity, the extent and competency of integrity monitoring, maintenance, testing, and verification plans, as well as the extent, competency and response capability of emergency action plans.

Consequence impact severity of a loss of containment event can be related to storage field or well deliverability at a casing-constrained open flow rate, the well count in a storage field, and each well's flow potential. Service reliability impact can be related to the consequence of taking the well and/or field out-of-service or changing the mode of operation due to an event. Safety consequences can be related to population density and proximity; environmental consequence impacts can be related to proximity to sensitive areas and the containment capability of an event's emission of fluid during/after an event.

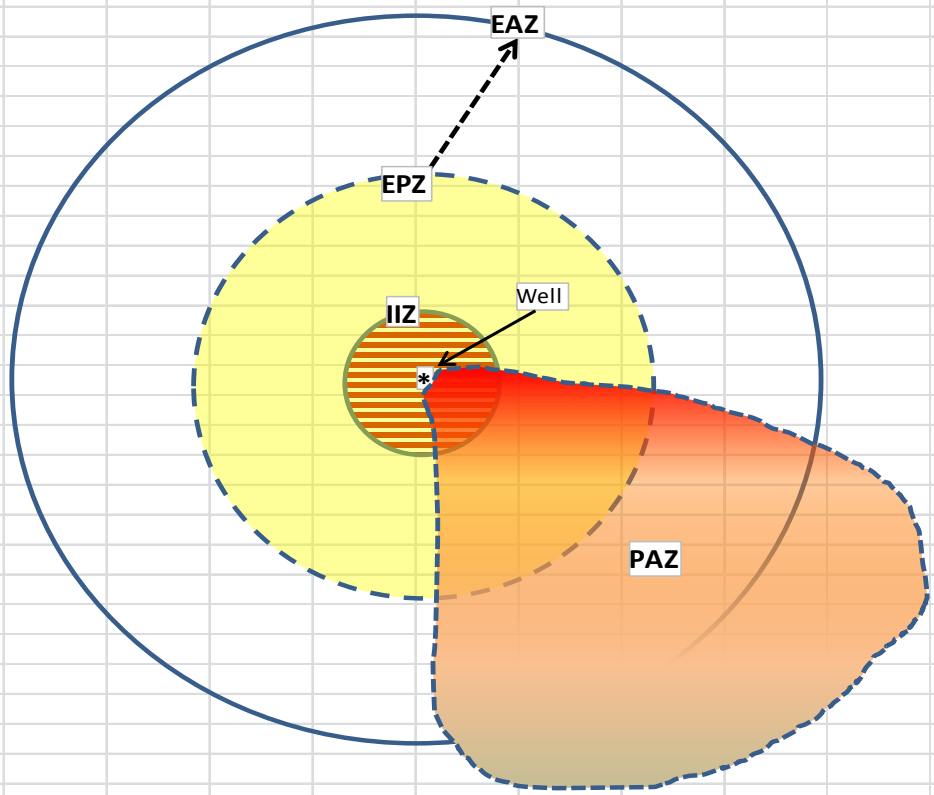
Literature review indicates that distances of 75-100 feet (~30m) or less render high risk estimates for well failure impact on receptors, although the impact radius is dependent on the well's flow capability (SPE #145428, Powell and Van Scyoc, "Well Site Screening: The Critical Few" – see Appendix 2 for a summary). If a well has any significant pressure and flow capacity, there is potential to adversely impact people, property, and the environment within such a close range. Operators can analyze consequence impact severity for gradually increasing distances away from a well, basing the analysis on flow rate, potential duration, fluid composition, noise, odor and heat/fire potential.

Downhole loss of containment represents a specific failure scenario. Operators can estimate impact radius and severity related to downhole loss of containment and potential migration in subsurface zones. Subsurface migration potential can be related to production casing and cement quality and isolation capability, the presence of permeable pathways in the uphole geologic strata, and the pressure and volume drive from the well and reservoir.

The population density around a well and workforce engagement in activities at/in a well must be assessed. Population density and proximity can be assessed at two levels – within an operator's assessment of immediate and/or potential impact radius, and at a wider radius which might be affected under specific circumstances of a release, such as those with a long duration, significant release volume, and widespread impact due to noise, noxious odor, or underground release and transport. The radius of impact is generally taken to be a circular area, with the immediate impact radius defining an area where isolation and removal or close monitoring of receptors is necessary – an "immediate/initial isolation zone" or "IIZ." A potential impact radius is an area that could be impacted if changes in the circumstances of an event cause an escalation of the event; such circumstances could include duration, flow, secondary effects such as fire, odor, liquids, external effects such as atmospheric and weather conditions, and changes in receptors during the course of the event. The potential impact radius can be

termed an “emergency planning zone,” or “EPZ.” An even wider radius of potential impact can be termed an “emergency awareness zone,” or “EAZ,” which is an area that could be impacted in specific events that include long duration, significant release volume, and widespread impact due to noise, noxious odor, or underground release and transport. During a specific event, conditions could be such that a protective action zone (“PAZ”) is determined for time- and condition-dependent factors, such as wind direction. The PAZ can change as influencing factors change, which requires operator awareness and incident command and control to set and communicate the emergency zones. The concept of a PAZ is that receptors inside the EPZ and/or EAZ might need specific protections or evacuations under special circumstances during a storage well release event. Storage operators can define the IIZ, EPZ, and EAZ, as illustrated conceptually below, for wells or groups of wells in their storage fields and describe in their emergency plans how these zones are determined.

Figure 3. Schematic of Storage Well Emergency Planning Zones. IIZ = Initial Isolation Zone, pre-defined; EPZ = Emergency Planning Zone, generally pre-defined and may expand to the EAZ = Emergency Awareness Zone. PAZ = Protective Action Zone, determined for time- and condition-dependent factors (wind, topography, etc.)



Site access for remedial and emergency equipment is a factor in the risk assessment. The ability to limit the consequences of a loss-of-containment event is evaluated by the operator on the basis of the emergency response plan quality (including training and readiness of the operator’s employees and contractors), the means of timely alert to or awareness of abnormal operating conditions at the well level (which requires the setting of well operating limits for pressure, flow, temperature, and annular conditions and then monitoring with those limits in mind), the ability to control the well via interventionist means (rather than by component means such as automatic or manual valves or reliefs),

and the time required to respond to an abnormal condition or a loss of containment condition and bring the well integrity back to a state of gas containment.

The added risk created by installation and servicing requirements relative to well equipment, such as the ESV system, should be analyzed. The installation of a subsurface safety valve carries a burden of well intervention to service the valve when it fails. The failure rate for safety valve systems can be estimated from operator testimonials and literature review. Much of the literature uses a data set from the offshore world. The operator testimonials add to existing literature and establish ranges of reliability and well re-entry frequency in the natural gas storage world.

Evaluation of Risk

The storage operator's evaluation criteria is used to rank and prioritize wells identified as having significant risks in the analysis step, and if necessary a further analysis and comparison can be conducted for decisions on use of an ESV system or alternative risk controls.

Storage operators have made many decisions regarding the installation and maintenance of ESV systems. Consensus decision-making has seen very few new installations of subsurface safety valves but somewhat a trend to replacing subsurface valves with surface safety valves. Operators have made decisions on ESV system use in complex, well-specific applications given the full range of site-specific risk inputs set against objectives of protecting people, property, and the environment, and protecting the workforce that must engage in well interventions and maintain service reliability.

It is the nature of risk management decisions that uncertainty remains after decisions are made. Storage operators can monitor the reliability of their storage wells, particularly those wells that have a surface or subsurface safety valve. Reliability information could be shared among operators in a uniform, consistent format so that a body of information could be assembled for learning and continual improvement in safety and reliability. The factors to which the risk analysis is most sensitive might be clarified, and, where appropriate, those same factors could be subjected to reliability improvement techniques.

Risk Treatment Alternatives

ESV systems are designed to activate in the event of a loss of containment or abnormal condition of flow, pressure differential, or variation in control energy. ESV systems are consequence mitigation devices and their effectiveness and value can be compared to alternative risk reduction measures.

The likelihood of a loss of containment event can be reduced by decreasing event initiator potential and/or increasing the redundancy of preventive barriers. The potential consequences of a loss of containment event can be reduced by employing mitigation barriers that reduce the duration and/or magnitude of the event. This section describes a number of alternatives to risk reduction. Operator data can be collected and analyzed to assess the effectiveness of alternative risk reduction measures, the reliability of risk reduction systems, and any new risk that might be introduced by each alternative.

Preventive Measures

Storage operators can employ protections to wellhead or near-wellhead pipe to prevent access and prevent vehicular collisions and animal and human interference. Surface methods can include installation of SSV on the wellhead or at the wing of the wellhead.

Operators could add downhole barriers or increase the robustness of existing downhole barriers if feasible, in order to add layers of protection so that if one barrier decays or fails, a second barrier exists to prevent loss of containment. Figures 4 and 5 show the concepts of barriers and the risk reduction by use of redundant barriers. Addition of tubing set into an isolation packer adds a layer of protection but restricts cross-sectional flow area.

Operators can assess the potential for successful addition of cement and advanced formation sealers in the area behind the casing. Cement can be added behind casing where it was not originally placed if deemed practical and cost-efficient. Remedial cementing could increase the amount of cement behind primary casing through perforating the casing and cementing, milling windows in the casing and cementing, or cutting and pulling free old casing and then inserting new liners and cementing the liners in place with a full cement sheath. When successful, such placement strengthens the cement sheath as a barrier to flow and as a next barrier to loss of containment should the casing fail. However, remedial cementing using these methods impairs the primary casing string by putting holes in the pipe, which must then be sealed. The impairment of the casing creates a new risk and the sealing method must be assured, or another barrier installed, such as a liner or tubing on an isolation packer or a liner cemented inside the casing.

Most of the options that increase the number and/or robustness of downhole barriers have an attendant reduction in cross-sectional flow area, which could lead to a need to drill additional wells to provide the same storage service capacity and reliability. All options, except those for liners cemented in place and cement additions, decrease reliability over the operating life cycle due to the introduction of additional mechanical components. The remedial or barrier addition options also can prevent or decrease the ease of use of other barrier monitoring tools such as casing inspection and fluid movement monitoring devices.

Passive physical barriers such as casing (liners) and cement have inherent reliability in that they are designed to function all the time to contain the stored gas and prevent back-side fluid movement. Storage operators can monitor the condition and effectiveness of the passive physical barriers to monitor the effects of time- and service-dependent decay modes.

Figure 4. Schematic Example of Single Barrier and Multi-Barrier Wellbore

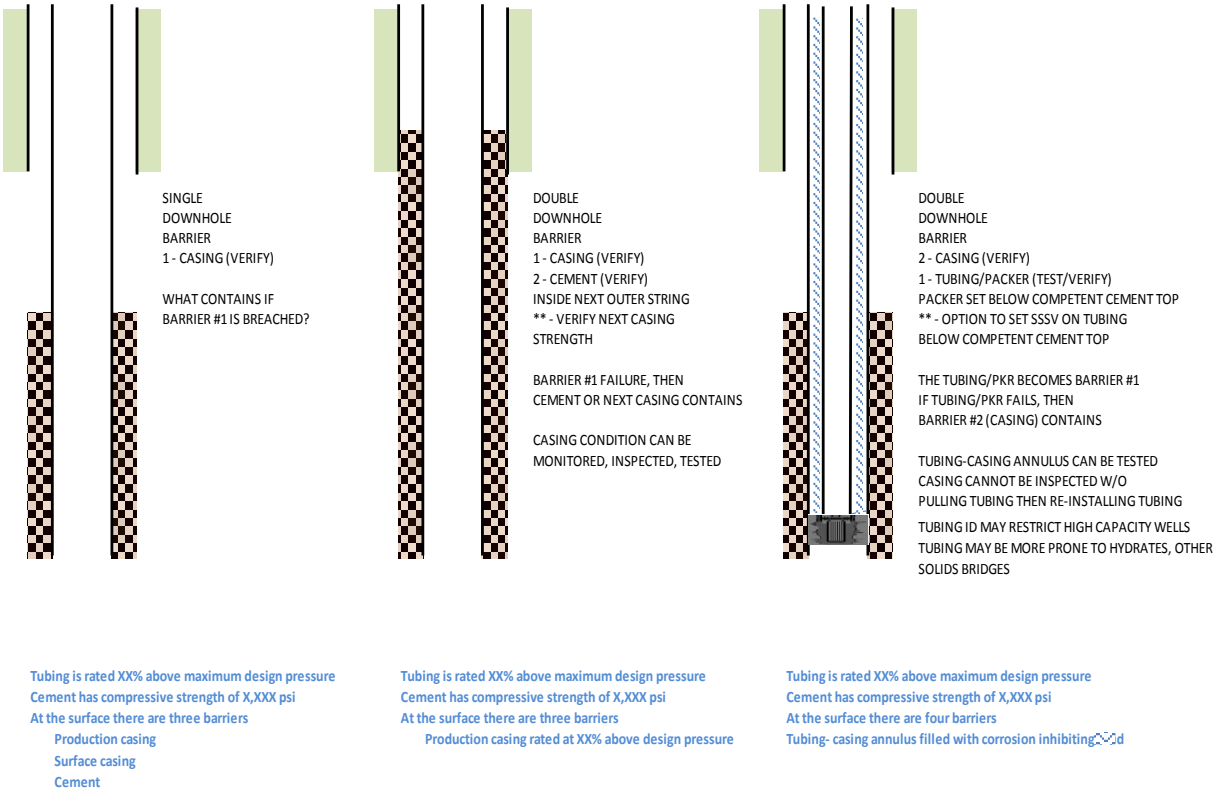


Figure 5. Example Risk Assessment Outline, Single Barrier Well

Monitoring, inspection, and testing of well barriers, using methods such as those described below, can reduce the likelihood of events by providing operators with information on barrier condition and effectiveness. Certain techniques requiring well intervention – the insertion of devices in a pressure-bearing well – come with the ever-present risk of loss-of-well-control.

Casing inspection logging with magnetic flux leakage tools can provide information on baseline casing condition and changes in casing condition by repeat surveys thereafter over the well life cycle. Casing condition affected by internal or external corrosion or mechanical wear events can be identified in such surveys. Ultra-sonic tools also can be useful in assessing casing condition and detecting certain anomalies. Operators generally look for consistency of methods over the course of time as each method of casing inspection has some weaknesses. Casing condition affected by significant earth movement events could be revealed by some types of casing inspection surveys such as internal calipers or downhole video surveys, if there is reasonable before- and after-event comparison capability.

Fluid analysis for chemical composition, microbial activity, and acid gases and water assist operators in understanding the corrosion potential of the well fluids and designing corrosion monitoring and mitigation programs. Ultra-sonic pipe wall thickness sensors can be used in above grade piping adjacent to wellhead to check for metal loss; this method is non-invasive and thus has no impact on deliverability or reliability.

Cement integrity surveys, typically with sonic-based tools, can verify the extent and fluid isolation potential of the cement sheath around the casing. Operators lacking knowledge of the cement condition can acquire this information as a means of performing well integrity assessments necessary to risk-based decisions.

Consequence Mitigation

The installation of an SSSV adds a downhole barrier designed to respond to an event, and thus by definition an SSSV is a consequence mitigation barrier. The SSSV activates in response to significant changes in pressure or flow or loss of hydraulic or pneumatic control - events that have a high threshold of deviation from the norm. For small deviations, it is possible, and in fact very likely, for the SSSV to not activate, as for example in the case of a well leak through a pin-hole or small corrosion or mechanical defect feature. The SSSV installation system can reduce cross-sectional flow area and increase the number of service interventions over the life of the well. Consequence mitigation by the SSSV is ineffective in a well where the loss of containment is below the valve or where the valve failed to function. Flexibility of well intervention is decreased by the presence of the SSSV. Kill options might be reduced due to the position of the SSSV and its cross-sectional flow area. The presence of the SSSV system could increase risk in the well intervention operations due to the additional tubing, the valve, and control lines. In the event any of the system is caught in the wellhead during an incident, the master gate valve might not function properly and the event intensity and duration could increase.

Flow and pressure monitoring at the wellhead, including annulus pressure monitoring, is an effective means of detecting abnormal operating conditions. Downhole pressure-temperature devices can be installed in wells to provide additional direct measurement closer to the reservoir; near-reservoir level monitoring could be a valuable addition to wellhead pressure and temperature monitoring in certain wells where significant pressure and temperature changes occur along the length of the well profile. A storage operator's pressure and flow monitoring program and training of staff to awareness of and

response to abnormal operating conditions is a consequence mitigation measure that can be highly effective in minimizing the impact of an event. Early detection of events and efficient response to events is essential to minimizing escalation and thus limiting consequences. Setting of well operating limits and monitoring and inspection of well operating conditions such as pressure, temperature, and flow rate are critical to detection of abnormal conditions to which a response should be given. Operators can assess the consequence mitigation value of data gathering and requirements and training around review of the data and actions in response to abnormalities relative to well operating conditions. Operators can make risk-informed decisions on changes to their program of data gathering and staff training in order to focus resources in the most necessary places and increase process safety reliability.

Well intervention in response to a loss-of-containment event is often practical in many wells and serves to mitigate consequences when the well can be safely entered. A full discussion of well intervention methods and safe work practices is not the intent of this Appendix. However a quick listing of potential intervention methods includes isolation of pressure and flow by setting downhole plugs by electric line or coiled tubing, killing the well by pumping fluid from the surface or through coiled tubing, or through a working tubing string snubbed into the well. In some wells, a deep-set packer can offer the opportunity to set a wireline plug to isolate the reservoir from the well above the packer set point. The deep-set packer system provides a benefit to entry and isolation of a well using a small diameter plug, smaller than the casing internal diameter, where the wellbore internal diameter might be restricted due to casing deformation or buildup of organic or inorganic scales and bridging materials that might preclude a full-bore plug from being set in the casing. Once the well is in a state of control it is possible to conduct additional work to investigate the loss of containment and begin remedial work.

A developed and tested emergency response plan that specifically addresses potential loss of containment events in storage wells during normal operation and during well drilling, servicing, or intervention is necessary to consequence mitigation. Operator emergency response plans should include definition of roles and responsibilities within an incident command structure, the communication and coordination with civil emergency responders, contractors and emergency response material sources, and assistance or coordination with industry partners who could be helpful if an event occurred. Operator personnel are expected to be familiar with the plan and trained in its application.

Emergency preparedness planning links to well integrity documentation. Well integrity assessments allow operators to document as-built and as-current conditions and provide information to the operator necessary for risk-informed decisions. Well integrity loss-of-containment incidents require decisions on whether or not to take the well out of service, repair the well, or plug and abandon the well. In the absence of loss of containment events, well integrity assessments help operators allocate risk management resources on those wells ranked highest in risk. Operators can focus well integrity assessment on wells within a specifically determined radius of places of habitation, roads, human gathering places, or environmentally sensitive areas. Operators can develop risk management plans for wells defined in the integrity assessments as located within a significant impact radius potential of receptors and with capacity to flow at high rates and/or long durations.

Section 6. Summary

Conclusions

The natural gas storage industry has experience using various forms of ESVs. This Appendix provides testimonials from five companies with thousands of operating well-years with ESVs and in total almost 200,000 operating well-years. The overall record of safety in terms of loss of containment events is in the frequency range described as "very unlikely."

Natural gas storage operators focus their well integrity efforts on the condition and effectiveness of the inherently reliable passive technical barriers of casing and cement. Operators can define as-built, as-identified conditions of barriers and define the limits of pressure and flow under which wells should be operated and monitored. Condition assessment of casing and cement are critical to ongoing integrity management. Installation of additional downhole equipment can impede or make more difficult the condition assessments of casing and cement.

A number of natural gas storage operators have used and still employ both SSV and SSSV. The use of either surface or subsurface ESV systems is an operator-based decision made in view of a wide variety of site-specific factors. Industry sources indicate that installation of a SSSV might decrease the risk by nearly an order of magnitude as compared to the risk due to failure of a primary barrier, such as casing. However, the effectiveness of an SSSV as an additional downhole barrier depends on its location and what the valve location is designed to protect or limit; the effectiveness of an SSSV also depends on the valve system reliability and the valve actuation potential against the potential created by an actual event.

SSSV reliability issues can increase potential for loss of containment events due to the well re-entry to pull and repair or replace the valve. Industry literature cited herein supports the company testimonies with respect to SSSV reliability issues. The reliability issues with SSSV detract from the risk reduction benefit gained by adding SSSV as a downhole barrier.

Storage operator testimony suggests SSSV systems have had, in some wells, adverse consequences on flow capacity and flow reliability, due to the flow profile restrictions that are part of the design of the valves and/or of the valve installation system.

The natural gas storage industry focuses on the values of safety, environmental stewardship and service reliability. Operators are expected to conform to API 1170 and API 1171 standards with respect to decision-making on use of ESVs. API 1170 and 1171 were developed by a consortium including state and federal regulatory agency representatives and some of the most knowledgeable natural gas professionals in the industry. The authors expect that the API 1170 and 1171 practices will be applied across the industry while recognizing the need for unique solutions because of the geological diversity, operator experience, and historical context.

The authors align with the recommendations made in PHMSA's Storage Advisory, Docket No. PHMSA–2016–0016: Safe Operations of Underground Storage Facilities for Natural Gas, with respect to decision-making around the use of ESV or alternatives. Specifically, the PHMSA advisory bullet #4 recommends periodic function tests for all ESV systems and the repair of deficiencies and failures, or the removal of the well from service, or employment of alternative and equivalently effective safety measures. PHMSA

advisory bullet #5 recommends that operators evaluate the need for subsurface safety valves on new, removed, or replaced tubing strings or production casing using risk assessment aligning to API 1171 criteria as a minimum, and that where subsurface safety valves are not installed, the operator use the risk assessment to inform decisions on integrity inspection frequencies, reassessment intervals, and well integrity issue or incident mitigation criteria.

Further the PHMSA advisory recommends that storage operators implement API 1170 and API 1171, and the Interstate Oil and Gas Compact Commission's (IOGCC) Natural Gas Storage in Salt Caverns—A Guide for State Regulators (IOGCC Guide). Developed under a joint effort of regulators and industry, API 1170 and API 1171 are based on the premise that well life cycle integrity management requires good design, construction and operating practices. For the operations life cycle stage, site-specific risk assessments and integrity program and plan inspection, monitoring, testing and well intervention and remediation tasks are to be based on the operator's risk assessments, knowledge, experience and skill.

Recommendations for Continual Improvement Actions

The risk assessment, decision and rationale regarding application or potential application of an ESV system on a natural gas storage well in a depleted hydrocarbon or aquifer reservoir is a duty of a storage operator under the requirements of API 1171, Clause 6.2.5. The authors highlight the risk management process recommended to operators for use in the decision-making processes. Good decision making is transparent and assesses the outcomes of past decisions.

The authors recommend that storage operators engage in the following continual improvement actions:

- ✓ Follow the risk management process and minimum evaluation requirements in API 1171, Section 8, and clause 6.2.5, and share lessons learned and good practices through industry associations;
- ✓ Follow the additional guidance around risk management discussed in this Appendix and establish a consensus as to some uniform, minimum risk management process detail;
- ✓ Develop templates and methods to gather and share information regarding reliability of various well barrier element system components, including surface and subsurface ESV systems;
- ✓ Establish partnerships between operator groups and stakeholder groups to evaluate reliability of ESV systems and system components, with goals to establish, evaluate, and report safety performance, and develop guidelines for good practices in integrity management and ESV system reliability management; and
- ✓ Collaborate through industry associations and regulatory agencies to develop common integrity management goals and establish regular forums where operating experiences can be shared and employee knowledge, skills, and experiences can be developed and enhanced.

APPENDIX 6.1. COMPANY EXPERIENCES AND OBSERVATION WITH RESPECT TO ESVs

The company testimonies represented in this Appendix are from five storage operators with a combined experience of nearly 200,000 well-years of operation and over 5000 well-years of operation of

subsurface safety valves. The five-company operator group represents a set of 68 depleted reservoir storage fields with over 3,400 wells, of which approximately 200 have subsurface safety valves and more than 200 have surface safety valves. The wells in this group represent operating pressures ranging from 200 psig to 4,000 psig and maximum flow rate potential of up to 500 MMcf/d.

Company A

Basic Statistics:

Of Company A's wells, nine percent have shallow, hydraulic surface controlled subsurface shut-off valves (SCSSV) and 15 percent of wellhead mains or their wing assemblies are pneumatically controlled by surface shut-off valves.

Brief Underground Storage History

Company A operates gas storage facilities in depleted reservoirs, aquifers, and salt caverns in conformance with all state and federal regulatory requirements. Several of the depleted reservoirs had subsurface shut off valves installed while in production service. As the fields, dating from the 1950s to 1980s, were converted to gas storage service and new wells were added, new surface controlled subsurface shut-off valves (SCSSVs) aka "disaster valves" or "downhole safety valves" (DHSV) were installed as a matter of conformity to past practices and because the term "safety" seemed to suggest a level of prudency. However, within a few years of installation, many of the subsurface shut off valves began to fail for a variety of reasons including but not limited to: sticking mechanisms, leaking hydraulic pumps and lines, control panel leaks, bad regulators, failed seals and flapper valves becoming stuck in open, closed, or partially open positions.

Company A's ongoing decisions to employ subsurface "safety," more aptly "shut-off" valves, are influenced by its risk assessments and experience with the reliability of DHSV systems. The valves are typically complex sliding or flapper devices, some consisting of more than 100 components, as shown in Figure 1, with tight clearances that can be contaminated, clogged, degraded, and worn, resulting in hydraulic leaks and valve failures. Because of reliability concerns, DHSV valves are no longer installed as a normal practice in new wells, and they are removed from existing wells when maintenance allows.

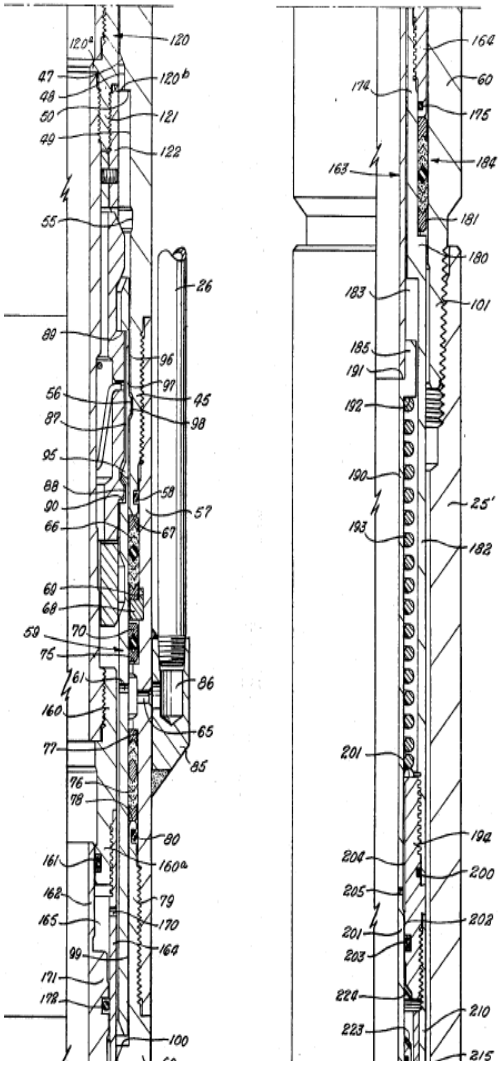


Figure 1. Disaster Valve US Patent 3874634

Reliability

Company A has experienced numerous DHSV failures across multiple storage companies using different manufacturer's subsurface shut-off valves. Company A's experience has been that the reduction in flow area through the valve presents an opportunity for hydrates, paraffin, salts, or other solids to build-up resulting in failure of the SCSSV. Additionally, there have been reliability issues with shut-off valve control line system hydraulics resulting in false closures, blockage of flow, and damage to inspection tools used for assessing well integrity. More than 50 percent of the SCSSVs originally installed in Company A's fields, over the lifetime of the well, experienced a reliability issue and have been removed or locked open for further analyses because a failure of the valve and/or its ancillary systems could have significant negative impact on gas deliverability during a critical period of market need.

Safety

SSSVs used in gas storage originated from the valves installed in subsea production wells where underwater mud slides could shear off the wellhead. SSSVs were believed to provide a fail-safe means of shutting in the gas storage well and isolating the conduit to the reservoir from any surface disaster, including complete shearing off of the wellhead assembly.

In the more than 40 years that Company A has been operating wells with SSSV assemblies, its gas storage fields have not experienced shearing at the wellhead. The majority of the wells are far from the roadway so that the threat of high-speed vehicular collision with a wellhead is remote. Collision risk events can be prevented by installing anchored fencing or guard/buttress systems.

Integrity

A risk related to DHSV/SCSSVs is from normal maintenance operations related to servicing the downhole valves themselves and the need to remove and re-install the valves due to other well work, such as casing inspections. The pressures that must be contained while removing the DHSV from a storage well range from hundreds to thousands of pounds per square inch, resulting in a force capable of launching heavy equipment into the air. Thus, working on a DHSV to maintain its integrity and reliability presents a level of risk that should be carefully considered.

DHSV/SCSSVs fit within the gas well casing and restrict the flow area reducing deliverability. This means wells with SCSSVs cannot be controlled with conventional plugs. In order to be inspected, deep DHSVs require the removal of thousands of feet of tubing while the well is under pressure. The risks during well work, and the restriction caused by the DHSV, and the additional methane that is released to remove and service the DHSV, are all factors that must be carefully considered before installing a DHSV.

Conclusion

Company A has been proactively analyzing its well integrity and removing failed DHSV/SCSSVs not only to prevent a catastrophic loss of gas deliverability to the market place, including residential heating and power plants during critical periods of need, but also to increase safety during work and maintenance to reduce methane emissions. Company A believes it is better to focus on gas well integrity rather than install valves downhole that in all likelihood will never be used and can actually increase the risk of an incident during well interventions.

Company C

Of Company C's portfolio, three percent of wells have hydraulically surface-controlled subsurface safety valves, and the majority of which are deep set and the rest are shallow set pusher type; additionally, one percent of wells have pneumatically controlled surface ESD valves.

Safety valves have been in service 10-30 years. Safety valves in service are in wells within a several hundred foot proximity to residences, businesses or schools. Company C had several safety valves in one field in the past due to coal mining. Decisions were made to plug these wells and not drill and complete future wells unless they are drilled through a pillar. Company C has had subsurface safety valves close due to control line leaks.

Subsurface safety valves in these storage wells drastically reduce flow by 40-50 percent, but the company has not noticed reduction in flow through wells with surface ESD valves.

The company decided to use concrete and or steel barriers around wells where necessary to reduce risk, as alternatives to safety valves.

Brief Underground Storage History

Company C operates storage facilities in depleted reservoirs, aquifers, and salt caverns in conformance with all state and federal regulatory requirements. Several of the reservoirs had SSSVs installed due to proximity to residences, schools, or were in an underground coal mining area. Safety valves are tested once a year to assure that SSSV will close and then are pumped open again. Most failures have occurred due to surface control failure. All storage wells are on a regular workover schedule which includes casing inspection logs. Each storage well has at least two casing inspection logs in its history. Wells are serviced every 10-15 years. The company has experienced one serious well control incident in the last 50 years.

Safety

The majority of Company C wells are in remote areas and it is the Company's assessment that SSSV are not warranted. Wells in fields with animals have either pipe or concrete barricades around the well. Generally 50% of the wells have either a safety valve or barrier around the well.

Company E

Basic Statistics:

Company E operates numerous depleted storage reservoirs, where approximately 2.5 percent of wells have shallow-set surface-controlled subsurface safety valves (SCSSVs), which are hydraulically controlled and approximately eight percent have surface-controlled surface safety valves (SCSVs) with a fusible element, which are hydraulically controlled and located in the wellhead stack (spring-actuated, fail closed design).

Brief Underground Storage History

Company E operates storage facilities in depleted reservoirs in conformance with all state and federal regulatory requirements. Several of the depleted reservoirs had SCSSVs installed while in original

production or conversion to storage operations once the fields were depleted. The remaining SCSSVs date from the late 1960s to early 1970s, with the exception of two valves which were installed in the mid-1990s. As the fields were converted to gas storage service and new wells were added, new subsurface control subsurface safety valves were generally installed as risk mitigation to wells within the flight path of neighboring aircraft. However, within a few years of installation, many of the subsurface safety valves began to fail for a variety of reasons, including increased corrosion of valve, materials plugging the valve bore, and reliability with the hydraulic control and tubing system used to control the valves.

Risk Basis for Safety Valve Installation:
Company E's current risk assessment considers the principles of API 1171 requirements, using the following factors in evaluating the potential applicability of any type of safety valve:

Flow potential of the well at maximum reservoir pressure

Proximity of the well to:

- ✓ People in permanent dwellings
- ✓ People in public gathering places
- ✓ Probable frequency/density of people in recreational areas
- ✓ Transportation corridors, public or private, including air, roads, rail, waterways
- ✓ Environmentally sensitive areas
- ✓ Other storage wells, storage infrastructure, or other industrial infrastructure
- ✓ Ability to control the well through fluid pumping (well kill) or other interventions
- ✓ Safety valve reliability experience and safety risk to well service personnel engaging in well interventions

Company E views safety valves as a mitigative measure in the event of a significant sudden failure of the gathering lines, the near-well flow line or other equipment adjacent to the wellhead. Casing failures at depth are possible but the event likelihood is remote, in the 1x10E-4 to 1x10E-5 range (published literature). Company E operates in a region where forces causing induced stress on wells and casing are remote, leaving human causes as the main influence in well operation / catastrophic failure potential.

Of all the analytical factors, the proximity of the well to potential heat-affected radius (which is a result of maximum flow rate) are the most heavily weighted factors in decisions on whether to employ a safety valve.

Reliability:
Company E has experienced numerous failures with the same manufacturer's subsurface safety valves. Experience indicates a reduction in flow area through the valve presents an opportunity for hydrates, paraffin, salts, or other solids to build-up. The build-up may result in a failure of the SCSSV to operate as designed. Additionally there are reliability issues with safety valve control systems and hydraulics resulting in false closures.

Company E has documented valve malfunctions and test failures, and those failures necessitated additional well interventions.

Safety:
The SCSSVs systems were originally installed to provide a fail-safe means of shutting in the well and isolating the conduit to the reservoir from any surface disaster, including complete shearing off of the wellhead assembly.

In the nearly 50 years that Company E has been operating wells with SCSSVs, the system has never experienced an incident which threatened a violent shearing at the wellhead. The majority of the wells are not located near roadways, so the threat of high-speed vehicular collision with a wellhead is remote. A majority of these wells are protected against collision by a guard rail. The wells do not exist in a high-risk earthquake or earth shear zone. Some wells do exist proximal to flight paths of heavy and/or high speed aircraft, but the probability of occurrence is remote. Likewise, sabotage or terrorist acts could target wellheads, but individual wells can be considered at low risk of being targeted due to their distance from the general public and due to the choices of easier targets.

The biggest risk with SCSSVs is from remedial operations related to servicing the safety valves themselves or the need to remove and re-install the valves due to other well work, such as casing inspections. This is noted extensively in the professional literature.

If the risk of well incident or worker injury is present every time a valve is retrieved and reinstalled, then company personnel have had several hundred well intervention events in their operating history where an incident could have happened. In the same time frame, the company is aware of three insignificant collisions with a wellhead in the system (light duty trucks and farm equipment). The company has never experienced plane crashes or terrorist events at or near any wellhead. The company's experience and knowledge of similar operators' experiences mimics professional literature, in that risks during well intervention are significantly more likely to create an incident than shearing of a wellhead.

During the 1990s, Company E reached a point where about 10% of wells had SCSSVs. Nearly 75% of the SCSSVs have subsequently been removed since the mid-1990s. The SCSSVs were originally removed during corresponding well interventions, but a specific program to actively remove the SCSSVs and replace them with SCSVs was initiated in the early 2000s.

<u>Company J</u>

Basic Statistics and History:
Company J operates a relatively small fleet of wells but approximately 30 percent of wells have SCSSV.

Reliability:
Company J has experienced multiple problems with subsurface safety valves installed in the 1980's. As Company J did not keep detailed logs of SSSV maintenance prior to 2016, Company J cannot substantiate if the failed SSSVs were properly maintained per the manufacturer's specifications.

- In testing and maintaining SSSVs, Company J has documented eight valve test failures. These failures were not limited to one facility or location.
- Company J currently has seven SSSVs that it has decided not to test or operate as Company J has observed similar SSSVs fail in a closed position. Company J highly believes that a significant

percentage would fail closed if operated and would require an immediate wireline job to reopen the SSSV to operate the well.

- Company J plans to remove SSSV from two wells and not reinstall or replace the valves.
- Company J has observed reliability issues with safety valve control line system hydraulics resulting in false closures, and flow restrictions.

Safety:
SSSVs were installed to prevent a loss of containment and provide an additional shut-in mechanism at the wellhead.

- In its operating history, no Company J wellhead has been sheared. No incidents or near misses that could have caused wellhead shearing.
- The majority of Company J's storage fields are in remote or rural locations away from densely populated areas and major roads.
- Placement of SSSVs is along roadways and structures intended for human occupancy.

Subsurface safety valves are not a panacea as they can complicate operations, may limit tubing inspection options, and require additional maintenance.

<u>Company S</u>

Basic Statistics:
In Company S' portfolio, 12 percent of wells have shallow-set surface-controlled subsurface safety valves, hydraulically controlled, three percent have surface safety valves, pneumatically controlled, on the wellhead and/or at the immediate wing of the wellhead.

Risk Basis for Safety Valve Installation:
Company S' risk assessment follows the principle of API 1171 requirements (at Section 6.2.5), using the following factors in evaluating the potential applicability of any type of safety valve:

Flow potential of the well at maximum reservoir pressure

Reservoir storage volume and depletion rate potential

Proximity of the well to:

- People in permanent dwellings – immediate radius
- People in public gathering places – immediate radius
- Probable frequency/density of people in recreational areas
- Transportation corridors, public or private, including air, roads, rail, waterways – immediate radius
- Environmentally sensitive areas – immediate radius
- Other storage wells, storage infrastructure, or other industrial infrastructure
- Population density in a wider (three to five mile) radius

Ability to control the well through fluid pumping (well kill) or other interventions

Safety valve reliability experience and safety risk to well service personnel engaging in well interventions

Fluid composition – range of gas composition, liquid hydrocarbon potential, freshwater potential, saltwater potential

Well construction (as built, current state), including number and quality of casing and cement sheath barriers, and the casing geometry (diameter, inclination, depth)

Company S views safety valves as consequence reduction controls in the event of a significant sudden failure of the gathering lines, the near-well flow line or other equipment, the wellhead, or a near-surface (shallow-depth) casing rupture or shear. Casing failures at depth are possible but the event likelihood is remote, in the 1x10E-4 to 1x10E-5 range (company experience and published literature). Casing failures with apertures large enough to have significant flow rates must be induced by human or natural forces that place increased tensile, compression, or axial force on casing, which might be weakened by time-related degradation mechanisms such as corrosion. Drawing on the extensive operating history in the areas where Company S operates, Company S knows that natural forces causing induced stress are rare, leaving human causes as the main influence in well operation/catastrophic failure potential.

Likelihood analysis (of a large rupture) is driven by the as built/current state of the well and the well's proximity to strike impact or potential stress-inducing forces.

Consequence analysis is driven by well potential, reservoir volume and rate of pressure depletion, proximity to sensitive receptors (people, environment, other infrastructure, particularly in an immediate radius affected by heat stress and ignition potential should an uncontrolled well flow ignite), and fluid composition, and consequence reduction measures including kill potential, emergency preparedness and anticipated effectiveness of emergency response measures including response time and perceived well controllability.

Of all the analytical factors, the proximity of the well to impact receptors or impact deliveries and the potential heat-affected radius (which is a result of maximum flow rate) are the most heavily weighted factors in decisions on whether to employ a safety valve.

Company S' ongoing decisions to employ safety valves is influenced by its experience in the reliability of safety valve systems.

Reliability:
Reliability is expressed in valve function failure during normal operation, or valve failure during semi-annual function tests. Experience has been that the upper assembly creates a restriction that is a favorite hydrate, paraffin, salt, or other solids bridging area, leading to decreased reliability and time and expense involved in finding and remediating the bridging. There have been reliability issues with safety valve control line system hydraulics and false closures due to control line leaks or temperature changes.

Company S has seen valve malfunctions and test failures at a rate of one to two percent of all valves in inventory per year (0.015 failures per well-year of operation).

The total entry-and-removal/replacement of subsurface safety valves has a rate of 0.141 entries per well-year, composed of 0.047 entries per well-year for SV inspection and repair, 0.015 per well-year for

test/function failures, and 0.079 per well-year for casing inspection. Thus, the reliability issue reasons for re-entry are ~0.062 entries per well-year.

The total re-entry rate is a significant factor in the safety impact analysis used in decision-making around safety valve disposition.

In addition to well re-entry to pull the valves, Company S has tracked flow and function reliability issues related to downhole safety valves for the period 2005-2016. Flow and function reliability issues include hydrates, salt, or paraffin bridging in the safety valve assembly, or function test failures due to the same types of bridging agents fouling the flapper closure mechanisms. Although 2016 represents a partial year thus far, the corrective maintenance issue (reliability issue) rate is 0.151 per well-year of operation. Company S observes that the annual corrective maintenance rate varies from as low as 0.061 per well-year in warm, small-withdrawal volume winters to 0.224-0.293 per well year in cold, deep-withdrawal winters. The overwhelming majority of corrective maintenance actions involve flushing with solvents such as water, methanol, or heated diesel oil, and in over 90 percent of instances these are successful in restoring flow and proper valve function.

Safety:
The SSSV systems were installed in order to provide a fail-safe means of shutting in the well and isolating the conduit to the reservoir from any surface disaster, including complete shearing off of the wellhead assembly.

In the more than 36 years that Company S has been operating wells with SSSV assemblies, the system has never experienced an incident that approximated or threatened a violent shearing at the wellhead. The majority of the wells are far from any roadway so that the real threat of high-speed vehicular collision with a wellhead is extremely remote, and such an event can be protected against via anchored fencing or guard/buttress systems. The wells do not exist in a high-risk earthquake or earth shear zone. Certain wells do exist more proximal to flight paths of heavy and/or high speed aircraft; although a well blowout from a plane crash is protected against with a SSSV given the depth of setting, such events have a very low probability of occurring. Likewise, terrorist acts could take out wellheads, but individual wells can be considered at low risk of being targeted due to their distance from the general public and due to the choices of easier targets.

The biggest risk related to surface-controlled subsurface safety valves is from remedial operations related to servicing the safety valves themselves or the need to remove and re-install the valves due to other well work, such as casing inspections, and this has been noted over the years in the professional literature. For example, a 1985 Journal of Petroleum Technology (JPT) article ("Subsurface Safety Valves: Safety Asset or Safety Liability?", Busch, Policky, Llewelyn, JPT October 1985) quoted a survey of well blowouts from 1979-1982 (in the non-communist world). Of the 271 blowouts, 216 were blowouts while drilling and 55 were production related. For the production related blowouts, the largest percentage (14 of 55) occurred during workover operations.

If the risk of well incident or worker injury is present every time an upper assembly is retrieved and reinstalled, then Company S has had several hundred well intervention events in the past 36 years where something could have happened. The Company S experience and knowledge of similar operators' experiences mimics that reflected in the literature, which is that risks during well intervention

are more likely to create an incident than is the chance that a more direct disastrous event, such as a casing failure or combined casing/cement failure, would create an incident.

While it is prudent to maintain the SSSV systems because of the prevalent need to provide a fail-safe shut down of the well conduit to the reservoir and protect workers, the public, and adjacent infrastructure, Company S looks for ways to minimize the interventions that invite incidents.

Regulatory requirements to install subsurface safety valves and full tubing strings on all Company S wells would require ~$150-$190 million for existing wells and addition of ~75 new wells at ~$120-$140 million in order to retain the same storage service capabilities. Maintenance rates would increase, causing O&M expense to increase by $2-4 million per year ($40-120 million over 20-30 years) and the risk of loss of control due to well entry and service work would increase 10-12 fold, directly aligning with the increase in the number of safety valves and tubing/packer strings.

APPENDIX 6.2. INDUSTRY LITERATURE REVIEW – OPERATING EXPERIENCE

A ***2005 Gas Research Institute study, Project No. 809833, RISK ASSESSMENT METHODOLGY FOR ACCIDENTAL NATURAL GAS AND HIGHLY VOLATILE LIQUID RELEASES FROM UNDERGROUND STORAGE, NEAR-WELL EQUIPMENT, performed by URS Corporation under Contract No. 8604,*** provided both a literature review and survey techniques to arrive at component reliability estimates and failure rates of storage wells from all component failures and combined reliability causes. A fault-tree analysis methodology was adapted and used to predict failure rates of 4.9E-05 to 7.7E-04 with and without a downhole safety valve (DHSV), respectively, and a sensitivity range using several well configurations and applying uncertainty ranges to variables to push the 'without safety valve' rate to 1.7E-04 to 7.7E-04. URS estimated the probability of the same types of releases catching fire to be lower, in the 2.1E-05 to 9.7.E-05 range.

From survey data, URS estimated well failures occurring due to downhole safety valve maintenance at 1.78E-05, which is somewhat less likely than failures due to cement (6.4E-05) but similar to failures due to casing failure (1.6 to 2.9E-05) vehicular strikes (1.78E-05) and falling objects (1.34E-05). All these individual rates are “very unlikely” in terms of likelihood of occurrence.

Safety valve failures to close on demand are in the range of 1.95E-05 to 4.38E-06 per demand and surface safety valves by analogy are interpreted as having a failure to close at a very low 7.01E-08 per demand.

It is worthwhile noting that “failure” resulting in gas release during a well drilling or re-entry for service is one to two orders of magnitude greater than most failures due to well equipment: 3.41E-04 to 8.91E-05 per entry.

URS noted in the report that process safety general principles understand that the number of catastrophic incidents is a small percentage of lesser incidents that could have had catastrophic results; API 754 and other process safety standard performance indicator tiering apply this understanding.

URS noted that record keeping and data analysis were key to studying reliability and failure in a quantitative fashion, and encouraged uniform tracking of industry data for reliability issues and failures at the component level, along with evaluation of maintenance activities and reliability engineering improvement efforts, in order to develop continual improvement.

Moines and Iversen (1990, OTC 6462, Reliability Management of Subsurface-Controlled Subsurface Safety Valves for the ROGI Project), demonstrated in a 1990 paper that SCSSV failure was the primary cause of workover operations initiated due to completion equipment failures in offshore operations – 450 per 10,000 well years. The authors noted that reliability methods can be used to increase reliability and in particular that working with the manufacturer to enhance reliability in the design phase was essential. The paper reviews seven configurations of downhole safety valves, from shallow set, tubing retrievable surface controlled systems to deep set, surface controlled systems; the shallow systems were complemented with dual safety valves. Reliability data indicate that the deep set systems fare poorest, with failure rates of 1-3E-04 and shallow systems at 0.6-0.8E-04; the various dual-valve combinations reduce failure by an order of magnitude, to 0.3-0.6E-05.

Moines and Strand followed up in 2000 with SPE #63112, "Application of a Completion Equipment Reliability Database in Decision Making", where historical evolution in reliability of subsurface safety valves (SCSSV) is demonstrated from what was largely a North Sea data set. The paper advocates a screening matrix to characterize risk and push the bounds of risk acceptance given consequence analysis so as to not compromise safety overall. Increasing test frequency is advised when there is an actual failure or a heightened risk of a well barrier failure.

Moines and Strand look at the issue of SCSSV removal from subsea completions and suggest that this be addressed on the basis of local/regional requirements and likelihood and consequence impact factors. The authors note a significant improvement in SCSSV performance occurred in their data set from Mean Time to Failure (MTTF) of 14.2 years in 1983 to 36.7 years in 1999. A trend toward design standardization using single rod piston, flapper type tubing retrievable safety valves without equalizing feature is credited with the increased SCSSV reliability and reduction in well interventions. SCSSV reliability improvements can be made by applying a system reliability approach encompassing the valve and its mechanical components as well as the control line, control line protectors, tubing hanger/x-mas tree interface and the surface hydraulic control unit.

Durham and Paveley, SPE 56934 "Radical Solutions Required: Completions Without Packers and Downhole Safety Valves Can Be Safe", 1999, found blowout frequency during workover in the 6.8E-04 range for their data set, with SCSSV workover frequency .02-.03 per year. The authors assess likelihood and consequence, where consequence is on a safety-environment-cost basis, and show that that the elimination of packers and downhole safety valves from completions can be tolerated, providing an increase in cost efficiency through reduction in equipment and well interventions. The risk assessment method includes fault trees and failure mode, effect, and criticality analyses, combined with quantitative analysis of an uncontrolled hydrocarbon release.

A key to the methodology is the addition of loss of control risk due to equipment failure. The authors establish loss of control frequencies for component failure and for workovers from worldwide data, then they relate completion component reliability to the need for workover to get the combined risk. Like a fault tree, the release potential is the sum of component failure leading to loss of containment plus the chance of workover loss of control, where workover loss of control is component failure rate=well workover rate multiplied by the chance of a workover loss of control incident.

Secondary controls can be employed to reduce criticality of a loss of control failure into the tolerable range with or without a safety valve, and these include gas/flame detection monitoring equipment, annulus pressure monitoring, emergency plans in place for rapid response well kill or control, pressure test verification of containment barriers, pressure monitoring and control equipment, and, during workovers, regular BOP testing and maintenance of dual barriers.

A downhole safety valve reduces consequences of relatively few events and only during normal operations, so the authors advise that the consequence level be assessed quantitatively. The likelihood of a loss of containment event during normal operations is low but the service of the valves has a greater chance of loss of control.

Powell and Van Scyoc (2011), SPE #145428, "Well Site Screening: The Critical Few", note that risk screening should be applied to define the most critical wells and then resources expended at those sites to gain the most benefit. It is impractical and unnecessary to use the same integrity maintenance, monitoring, and verification strategy at every well, and, rather, operators should see more rigorous

integrity management practices at high risk wells. Powell and Van Scyoc developed and applied a structured risk assessment approach, with a goal to reduce risk to as low as reasonably practicable for continued safe operation.

Powell and Van Scyoc assessment criteria included well type and status (a reflection of the well as-built and current condition), maximum well pressure, maximum/normal flow rate, and fluid production characteristics as inputs, along with consequence impact attributes ranked by H2S exposure, flammability limits, and extent of liquid pool spread for releases at the surface, all compared to distance to population and environmental receptors. The authors divided their well set into three tiers defined relative to the H2S radius of exposure, gas dispersion radius at 50 percent of the lower flammability limit, and a 24 hour liquid release spread radius; the tier divisions, they noted, generally reflected regulatory practices and were otherwise conservative. Thus, the authors used a consequence-basis to risk-tier their wells without respect to likelihood for a well failure. The risk-tiers support different levels of integrity activity requirements – testing, inspection, monitoring, and other activities, including for the highest risk wells.

Powell and Van Scyoc noted lessons learned from the application of the screening. First, the method had no approach to handle downhole, subsurface product releases. Such a model or method is necessary, along with guidance for inspection, testing, and monitoring programs. Second, the method does not permit input variables that might be related to more than one release scenario (casing, tubing, flowline scenario for a single specific well). Input variables could be established for various well types, for which separate impact evaluations could be done for multiple major release scenarios. Third, they identified a need to incorporate wellbore fluid levels, well type, and pressure for screening impact susceptibility of underground sources of drinking water.

APPENDIX 6.3. ADDITIONAL NOTES AND GUIDANCE ON THE RISK MANAGEMENT PROCESS

Determining objectives and internal/external context

Each gas storage operator sets risk management objectives in the context of their own company's internal operating environment and capability. The operating environment includes the company's operating history and institutional knowledge, organizational structure for command-and-control of resources and influence by internal stakeholders. A company's capability is influenced by the knowledge, skills, and experiences of individual contributors, corporate structures, and the embodiment of controls within procedures, training, supervisory control and reinforcement and continual improvement activities.

The gas storage operator sets the risk management objectives in the context of the external operating environment, which includes, at a minimum, the concerns of public stakeholders and regulatory agencies, regulatory trends, natural gas infrastructure development and enabling trends, gas storage business trends, industry concerns as embodied in/through industry associations, industry recommended practices and guidelines, professional literature, academic research, and a wider body of knowledge, skills and experiences than any one company could have.

The risk analysis method – various forms of qualitative, semi-quantitative, or quantitative - depends on the company's capability, in and through its individual contributors' capability, to apply the risk analysis method in a consistent manner and achieve meaningful results. If past data aggregation and analysis has not been quantitative, it might be difficult initially to apply fully quantitative methods.

A similar risk analysis methodology could be desirable across the industry; however, one approach might be to start at a basic, semi-quantitative level, advising collection of reliability and safety data, so that continual improvement can be achieved along a path to more fully quantitative risk analysis methods. Industry literature reviewed indicates that there is potential to begin at a semi-quantitative level since some general failure rates are known and safety valve reliability experiences are known by some operators.

Analysis of risk: well-specific applications

Similar to impact factors and assessments used by Powell and Van Scyoc, storage operators could assess gas dispersion radius at 50 percent of the lower flammability limit, and a 24-hour liquid release spread radius. Alternatively, operators could apply CSA Z341.1 impact assessment following Gas Research Institute project GRI-00/0189 radius-pressure-casing size relationship, which uses worst case well flow capacity, ignition of the gas, and a heat flux of 5.0 kW/m2, representing a 30-second burn threshold.

Population density for widespread impact assessment could be tiered as follows:
0-1 per square mile
1-10 per square mile
10-100 per square mile
100-1000 per square mile
1000-10,000 per square mile
>10,000 per square mile

Operators can assess impact potential due to fluid composition and maximum flow potential in two ways: at the maximum daily rate, and at an extended duration. The operator can assess each well's maximum flow capability, constrained by casing inner diameter, at absolute wellhead flow potential at maximum pressure. The extended flow capability (extended release volume) of the well can be calculated over various intervals. The operator could assume a maximum case of decline in reservoir pressure solely due to a leak at the well, or assume a minimum case where in a period extended beyond a few days, field withdrawal could be orchestrated to bring reservoir pressure down more rapidly. The operator can assess the potential of the well to release product other than dry natural gas; wells that could produce water, liquid hydrocarbon, solids, or noxious or hazardous gas constituents could be rated as potentially more severely impactful. The volume of greenhouse gas emissions and the local/global impact can be addressed in the assessment.

Evaluation of Risk

The operator can develop a decision tree specific to the question of whether a safety valve system is needed at each well. For wells that already have a safety valve, the decision tree could help the operator to demonstrate that the safety valve system is needed and located in the best place, or that the safety valve system is needed but not located in the best place, or that the safety valve system is not needed.

When the risk evaluation indicates that a specific well's loss-of-containment potential and impact potential are severe enough to warrant evaluation of the risk reduction with a safety valve, the operator can evaluate alternative means of reducing risk. With each alternative, the operator can assess both the risk reduction potential of the alternative as well as the risk increase potential related to the alternative.

Worldwide, safety risk thresholds are values-based and often stated for individual risk in terms of fatalities per capita per year, and a near-universal threshold of unacceptable risk in a tolerable risk framework is one in 10,000 fatalities per capita per year, whereas a widely acceptable risk threshold on the lower end of a tolerable risk framework is at one in 1,000,000 fatalities per capita per year.

Environmental risk thresholds are not well-established. However, most guidance on risk acceptability scaling is a mix of values-based/bounded constraint/utility basis relating to the number and type of receptors impacted (which often relates directly to radius of impact and what is in the radius of impact), the environmental impact duration, and the environmental recovery time.

Service reliability risk thresholds are not well-established since the evaluation criteria are usually utility-based (cost/benefit); the risk acceptability scaling is site specific and relates to the local impacts, duration, and service alternatives.

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Ex. I - 9

SED Supplemental Data Response to SoCalGas Data Request 3
Supplemental information is shown in red as of 1/6/2020.
Supplemental information is shown in blue as of 1/15/2020.
Supplemental Information is shown in green as of 1/23/2020 As a general note, includes the following objection with all information provided in green. SED was relying on SoCalGas's response to SED Data Request 52 in order to supplement its answers to this response. However, SoCalGas's responses to SED Data Request 52 were non-responsive and/or incomplete, in the fashion described in the specific answers. Therefore, SED is unable to provide the supplemental information it indicated it would on January 15, 2020 at this time. SED encourages SoCalGas to re-consider its response to SED Data Request 52, and provide specific, directly responsive, and complete answers. Data dumps or references saying that SoCalGas has already provided SED information are not responsive to the questions. Rather, specific responses showing exactly which documents are responsive are required to answer the question.
At this time, SED stands by all objections it indicated it would re-consider at the last meet and confer.

General disclaimer: SED reserves the right to update Its data response, and has identified where SED requires more time in each answer. SED reserves the right to add to its answer to all question subparts requesting SED to identify the laws, rules, regulations and/or industry standards. Where SED has quoted from its testimony to answer a question, SED has omitted the footnotes from SED's testimony in the answer. However, these footnotes are all incorporated into each answer by reference.

1. YOU assert that SoCalGas failed to investigate the "blowout" from well Frew-3 (Violation 1 alleged in OPENING TESTIMONY).

a. Please describe the investigation that SED believes would have constituted an adequate response to the "blowout" from well Frew-3 on December 31, 1984.

SED objects to this question on the grounds that it mischaracterizes SED's testimony, and related role as the entity that is responsible for investigating this blowout. That is SoCalGas's (not SED's) mandated responsibility, pursuant to California Public Utilities Code Section 451. SED further objects to this question as unduly burdensome in that it requests SED to gather information related to the blowout that is or was in the control of SoCalGas, and analyze it to determine what type of investigation might have been adequate.

Despite the undue burden of this question, SED requires more time to answer this question, and reserves the right to provide an additional substantive answer.

b. Identify the laws, rules, regulations, and/or industry standards, if any, that SED believes require the investigation described in its response.

Despite, SED's objection to question 1a, SED understands this to be asking about the information from SED's testimony that is identified in the question, and answers accordingly. Please see the passage on SED Opening Testimony, pages 8 and 9, which states, "SED views SoCalGas's failure to investigate or analyze the failures or root causes of casing leaks, parted casings, or other failure events as separate violations of Section 451 as follows:

- One violation for failure to investigate the blowout from well Frew-3 spanning

from December 31, 1984, the last possible date of the blowout, to October 23, 2015, the date of the incident.

c. Identify and produce all DOCUMENTS, aside from the Blade Report, that support SED's contention that SoCalGas failed to investigate the blowout from well Frew-3.

SED relies on the Blade Report for this violation. SED may update this answer at a later time.

d. Identify the basis on which YOU contend that this alleged failure is a violation of California Public Utilities Code Section 451 ("Section 451").

The basis for this violation is provided in Section II.B of SED's opening testimony. See also the answer to question 1b.

2. YOU assert that SoCalGas failed to investigate the "blowout" from well FF-34A (Violation 2 alleged in OPENING TESTIMONY).

a. Please describe the investigation that SED believes would have constituted an adequate response to the "blowout" from well FF-34A on December 31, 1990.

SED objects to this question on the grounds that it mischaracterizes SED's testimony, and related role as the entity that is responsible for investigating this blowout. That is SoCalGas's (not SED's) mandated responsibility, pursuant to California Public Utilities Code Section 451. SED further objects to this question as unduly burdensome in that it requests SED to gather information related to the blowout that is or was in the control of SoCalGas, and analyze it to determine what type of investigation might have been adequate.

Despite the undue burden of this question, SED requires more time to answer this question, and reserves the right to provide an additional substantive answer.

b. Identify the laws, rules, regulations, and/or industry standards, if any, that SED believes require the investigation described in its response.

Despite, SED's objection to question 2a, SED understands this to be asking about the information from SED's testimony that is identified in the question, and answers accordingly. Please see the passage on SED Opening Testimony, pages 8 and 9, which states, "SED views SoCalGas's failure to investigate or analyze the failures or root causes of casing leaks, parted casings, or other failure events as separate violations of Section 451 as follows:

- One violation for failure to investigate the blowout from well FF-34A, spanning from December 31, 1990, the last possible date of the blowout, to October 23, 2015, the date of the incident.

c. Identify and produce all DOCUMENTS, aside from the Blade Report, that support SED's contention that SoCalGas failed to investigate the blowout from well FF-34A.

SED relies on the Blade Report for this violation. SED reserves the right to update this answer at a later time.

d. Identify the basis on which YOU contend that this alleged failure is a violation of Section 451.

The basis for this violation is provided in Section II.B of SED's opening testimony. See also the answer to question 2b.

3. YOU assert that SoCalGas failed to investigate the three parted casings discovered on December 31, 1994 (Violation 4 alleged in OPENING TESTIMONY).

a. Please describe the investigation that SED believes would have constituted an adequate response to the three parted casings discovered on December 31, 1994.

SED objects to this question on the grounds that it mischaracterizes SED's testimony, and related role as the entity that is responsible for investigating the parted casings. That is SoCalGas's (not SED's) mandated responsibility, pursuant to California Public Utilities Code Section 451. SED further objects to this question as unduly burdensome in that it requests SED to gather information related to the question that is or was in the control of SoCalGas, and analyze it to determine what type of investigation might have been adequate.

Despite the undue burden of this question, SED requires more time to answer this question, and reserves the right to provide an additional substantive answer.

b. Identify the laws, rules, regulations, and/or industry standards, if any, that SED believes require the investigation described in its response.

Despite, SED's objection to question 3a, SED understands this to be asking about the information from SED's testimony that is identified in the question, and answers accordingly. Please see the passage on SED Opening Testimony, pages 8 and 9, which states, "SED views SoCalGas's failure to investigate or analyze the failures or root causes of casing leaks, parted casings, or other failure events as separate violations of Section 451 as follows:

- Four violations: One for failure to investigate each of the parted casings discovered between 1969 and 1994. As one of the parted casings must have been discovered in 1969 to set the beginning of the range, that first violation spans from December 31, 1969 the last possible date of its parting, to October 23, 2015, the date of the incident. Assuming that the remaining three parted casings were discovered December 31, 1994, those three separate violations each span from, at the latest, December 31, 1994 to October 23, 2015.

c. Did SED ever conduct an audit of SoCalGas relating to whether SoCalGas investigated the three parted casings discovered on December 31, 1994.

SED objects to this question as unduly burdensome on the grounds that it asks a question that SoCalGas does or should have the answer to. SoCalGas is or should be aware of audits that SED has conducted on SoCalGas. SED notes as part of its objection that SoCalGas should avoid asking questions to which SoCalGas does or should already have the answer in that they waste the limited time and staff resources of SED in this investigation. Failure to heed this instruction may result in SED identifying additional examples in which SoCalGas is not cooperating with SED's investigation.

d. Identify and produce all DOCUMENTS, aside from the Blade Report, that support SED's contention that SoCalGas failed to investigate the three parted casings discovered on December 31, 1994.

SED relies on the Blade Report for this violation. SED may update this answer at a later time.

e. Identify the basis on which YOU contend that this alleged failure is a violation of Section 451.

The basis for this violation is provided in Section II.B of SED's opening testimony. See also the answer to question 3b.

4. YOU assert that SoCalGas failed to investigate the first parted casing in 1969 (Violation 3 alleged in OPENING TESTIMONY).

a. Please describe the investigation that SED believes would have constituted an adequate response to the first parted casing in 1969.

SED objects to this question on the grounds that it mischaracterizes SED's testimony, and related role as the entity that is responsible for investigating this parted casing. That is SoCalGas's (not SED's) mandated responsibility, pursuant to California Public Utilities Code Section 451. SED further objects to this question as unduly burdensome in that it requests SED to gather information related to the question that is or was in the control of SoCalGas, and analyze it to determine what type of investigation might have been adequate.

Despite the undue burden of this question, SED requires more time to answer this question, and reserves the right to provide an additional substantive answer.

SED requires a complete answer to Data Request 52, Question 2 as a condition precedent to completing the answer to this question. For reference, that question asks:

Related to AC_CPUC_SED_DR_27_0000351 July 20, 1962, Tidewater prepared an evaluation of the SS reservoir for future Sesnon Gas Storage distributed for review before August PUC hearings. Please provide all correspondence, reports, studies and testimonies, and the final contract for acquisition of the Sesnon Gas Storage field that occurred between 1962 and 1973 between Tidewater (and its associates),

Pacific Lighting, and the PUC regarding assessment and acquisition of the Sesnon Gas Storage (Aliso Canyon).

In DR 52, Question 2, SED asked, Related to AC_CPUC_SED_DR_27_0000351 July 20, 1962, Tidewater prepared an evaluation of the SS reservoir for future Sesnon Gas Storage distributed for review before August PUC hearings. Please provide all correspondence, reports, studies and testimonies, and the final contract for acquisition of the Sesnon Gas Storage field that occurred between 1962 and 1973 between Tidewater (and its associates), Pacific Lighting, and the PUC regarding assessment and acquisition of the Sesnon Gas Storage (Aliso Canyon).

SoCalGas answered, SoCalGas objects to this request on the grounds that it is vague and ambiguous, and overly broad and unduly burdensome. SoCalGas further objects to this request to the extent it seeks information that is outside the scope of this proceeding as set forth in the Assigned Commissioner's Scoping Memo and Ruling dated September 26, 2019. Subject to and without waiving the foregoing objections, SoCalGas responds as follows. Please refer to SoCalGas' previously provided response to SED Data Request 17 ("DR- 17") dated March 30, 2018.

SED views this as a non-responsive answer to SED's good faith effort to ask SoCalGas a specific question, as the response to DR 17 is a data dump. Due to SoCalGas being non-responsive to SED's good faith efforts dispense of its duties to investigate SoCalGas from a safety perspective, SED will not add anything to this response at this time.

b. Identify the laws, rules, regulations, and/or industry standards, if any, that SED believes require the investigation described in its response.

Despite, SED's objection to question 4a, SED understands this to be asking about the information from SED's testimony that is identified in the question, and answers accordingly. Please see the passage on SED Opening Testimony, pages 8 and 9, which states, "SED views SoCalGas's failure to investigate or analyze the failures or root causes of casing leaks, parted casings, or other failure events as separate violations of Section 451 as follows:

- Four violations: One for failure to investigate each of the parted casings discovered between 1969 and 1994. As one of the parted casings must have been discovered in 1969 to set the beginning of the range, that first violation spans from December 31, 1969 the last possible date of its parting, to October 23, 2015, the date of the incident.

c. Did SED ever conduct an audit of SoCalGas relating to whether SoCalGas investigated the first parted casing in 1969.

SED objects to this question on the grounds that It Is unduly burdensome. As the entity that was audited, SoCalGas has or should have the answer to this question. SED reminds SoCalGas, pursuant to the meet and confer in November, that questions such as this one, where SoCalGas already has the answer, wastes limited SED staff time and resources, and should not be asked. The instant question should be withdrawn.

d. Identify the basis for SED’s assumption that the first parted casing was discovered, at the latest, on December 31, 1969.

As noted on pages 8 and 9 of SED's opening testimony,

SED views SoCalGas’s failure to investigate or analyze the failures or root causes of casing leaks, parted casings, or other failure events as separate violations of Section 451, as follows:

> Between 1969 and 1994, four wells were discovered to have parted casings. However, Blade found no evidence that SCG prepared root cause analyses, collected samples, performed lab analyses, or taken photos of failures, or developed failure analysis reports to document these failures. The only documents found were well operations daily reports where on-site rig activities were reported.

Each of these sentences reference to, and are based upon page 165 of the Blade Report. As that part of the report notes that four wells were discovered to have parted casings between 1969 and 1994, SED assumes that at one well had a parted casing that was discovered the last possible date of 1969, because that would be the basis for the start date of 1969. SED conservatively assumes the last day of 1969 as the start date of that violation, the last possible day that first well discovery could have happened.

SED reserves the right to update the date of this violation from conservative assumptions to more concrete dates if SED discovers additional information.

e. Identify the date on which YOU understand SoCalGas took control as operator of the ALISO CANYON.

SED objects to this question on the grounds that it is unduly burdensome in that SoCalGas Is asking a question to which SoCalGas demonstrably does or should already have the answer. SED reminds SoCalGas to avoid wasting SED limited staff time and resources asking such questions.

f. Identify and produce all DOCUMENTS, aside from the Blade Report, that support SED's contention that SoCalGas failed to investigate the first parted casing.

SED relies on the Blade Report for this violation. SED may update this answer at a later time.

g. Admit that SoCalGas could not have violated any requirement or order of the Commission with respect to the maintenance and operation of Aliso Canyon prior to assuming control as operator of ALISO CANYON.

SED concedes this point, provided that SoCalGas had no role in ownership, maintenance, operation, or any control whatsoever. SED reserves the right to amend its testimony accordingly.

h. Identify the basis on which YOU contend that this alleged failure is a violation of Section 451.

The basis for this violation is provided in Section II.B of SED's opening testimony. See also the answer to question 4b.

5. YOU assert that SoCalGas failed to investigate the remaining 54 leaks (Violations 7-60 alleged in OPENING TESTIMONY).

a. Please describe the "investigation" SED believes would have constituted a reasonable

response to each of the “remaining 54 leaks.”

SED objects to this question on the grounds that it mischaracterizes SED's testimony, and related role as the entity that is responsible for investigating the leaks. That is SoCalGas's (not SED's) mandated responsibility, pursuant to California Public Utilities Code Section 451. SED further objects to this question as unduly burdensome in that it requests SED to gather information related to the question that is or was in the control of SoCalGas, and analyze it to determine what type of investigation might have been adequate.

Despite the undue burden of this question, SED requires more time to answer this question, and reserves the right provide an additional substantive answer.

Generally, the 2014 investigation of FREW 2 demonstrates the type of investigation that would be reasonable to determine the extent and cause of earlier leaks detected by SoCalGas. While 2014 tools may be more refined, the basic tools have been available for decades.

SED requires an answer to Data Request 52 Question 9 as a condition precedent to providing a complete answer to this question. For reference, that question asks:

> In addition to the SIMP Model Studies performed in 2014 on FREW 2, identify all other similar studies performed on other Aliso wells prior to October 23, 2015. For each study identified, provide a complete copy of the resulting report(s) that present log interpretations and results. Each report should be provided in separate, searchable pdf document(s).

In Data Request 52, Question 9, SED asked,

In addition to the SIMP Model Studies performed in 2014 on FREW 2, identify all other similar studies performed on other Aliso wells prior to October 23, 2015. For each study identified, provide a complete copy of the resulting report(s) that present log interpretations and results. Each report should be provided in separate, searchable pdf document(s).

In response, to this question, SoCalGas stated,

SoCalGas objects to this request as vague and ambiguous, particularly with respect to the phrase "SIMP Model Studies" and term "similar," overly broad, and unduly burdensome. Subject to and without waiving the foregoing objections, SoCalGas responds as follows. SoCalGas interprets this request to seek information about the SIMP Pilot Project. Please refer to SoCalGas' response to SED Data Request 25 ("DR-25") dated August 14, 2018. Rather than providing an answer to a direct specific question, this is a data dump, referring to over 1500 documents. It was during SED's review of SoCalGas' response to DR 25 that the SIMP Model Study report of corrosion on well FREW 2 was found. In an ongoing effort to give SoCalGas credit for all investigations into well corrosion and anomalies, SED asked for similar reports. Due to the non-responsive answer of SoCalGas, SED must assume that SoCalGas performed no other studies of wells prior to 2015 that would have identified corrosion or anomalies in well

tubings or casings. Therefore, SED has no further comments on this issue at this time.

Despite, SED's objection to question 5a, SED understands this to be asking about the information from SED's testimony that is identified in the question, and answers accordingly. As noted on pages 8 and 9 of SED's opening testimony,

SED views SoCalGas's failure to investigate or analyze the failures or root causes of casing leaks, parted casings, or other failure events as separate violations of Section 451, as follows:

a. To avoid double counting violations, SED assumes that the 60 leaks identified before the Aliso Canyon incident included the six blowouts and parted casings identified above. As such, the remaining 54 leaks that went without investigation should constitute a separate set of up to 54 violations. At the latest, these violations began on October 22, 2015, the last possible date before the incident on October 23, 2015.

c. Did SED ever conduct an audit of SoCalGas relating to whether SoCalGas investigated the remaining 54 leaks.

SED objects to this question on the grounds that It Is unduly burdensome. As the entity that was audited, SoCalGas has or should have the answer to this question. SED reminds SoCalGas, pursuant to the meet and confer in November, that questions such as this one, where SoCalGas already has the answer, wastes limited SED staff time and resources, and should not be asked. The instant question should be withdrawn.

d. Identify and produce all DOCUMENTS, aside from the Blade Report, that support SED's contention that SoCalGas failed to investigate the "remaining 54 leaks."

SED relies on the Blade Report for this violation. SED may update this answer at a later time.

Blade reviewed the well files and did not find any records that suggested an investigation to determine the cause of leaks was performed for the 54 leaks. Based on recent review of well file FREW 2 compared to the SIMP Study for well file 2, it appears that SoCalGas may only add logs to the Well File, not reports or findings. Therefore, SED requires an answer to Data Request 52 Question 9 as a condition precedent to providing a complete answer to this question. For reference, that question asks:

> In addition to the SIMP Model Studies performed in 2014 on FREW 2, identify all other similar studies performed on other Aliso wells prior to October 23, 2015. For each study identified, provide a complete copy of the resulting report(s) that present log interpretations, analyses, test results, and results. Each report should be provided in separate, searchable pdf document(s).

Please refer to additional response in green to Question 5a above.

e. Identify the basis on which YOU contend that this alleged failure is a violation of Section 451.

The basis for this violation is provided in Section II.B of SED's opening testimony. See also the answer to question 5b.

6. YOU assert that SoCalGas "did not properly follow its own 1988 plan to determine the condition of the casing in 12 wells" and SS-25. (OPENING TESTIMONY, page 10).

a. Please identify the law(s), regulations, or rules that required SoCalGas to test the production casing of its wells for metal loss on or about 1988.

SED objects to this question as mischaracterizing SED's testimony. SED's testimony asserts on page 10 that, "SoCalGas's failure to follow Its own 1988 plan to check the casing in 12 wells for metal loss violates Section 451." This violation does not discuss testing.

b. Please state the industry standard(s) for testing the production casing of oil and gas

storage wells that were in effect on or about 1988.

SED objects to this question as mischaracterizing SED's testimony. SED's testimony asserts on page 10 that, "SoCalGas's failure to follow Its own 1988 plan to check the casing In 12 wells for metal loss violates Section 451." This violation does not discuss testing.

c. Please identify all tools available, on or about 1988, which were designed to evaluate the metal loss in the production casing of oil and gas wells.

SED objects to this question as unduly burdensome. SoCalGas has access to the same information as SED, and can research the tools available at this time period as well as SED can, and this places an undue burden on SED to identify each tool available at the time. Notwithstanding this objection, SED identifies the following tools.

Tools available on or about 1988 that were designed to evaluate the metal loss in the production casing of oil and gas wells include the following:

Corrosion Logs were used to detect pitting and wall loss in casings as early as 1971. (*See* Donald L. Katz, AIME, U. of Michigan, "Monitoring Gas Storage Reservoirs," June 10, 1971, SPE PAPER No. 3287. *See also,* J.A. Bazzari, Getty Oil Co./Kuwait Oil Co., "Well Casing Leaks History and Corrosion Monitoring Study, Wafra Field," 1981, SPE PAPER No. 17930 (see log showing detection of wall thickness, Figure 4, page 53.)

Other tools designed to evaluate metal loss are included in the following passage:

"Corroded casing sometimes can be located by a high-resolution caliper log; spontaneous-potential logs have been used to locate depth intervals where active corrosion is taking place (Kendall, 1965). Commercial logging services are available for detecting corroded casing. An electromagnetic casing inspection log measures changes in the mass of metal between two coils; loss of mass may be due to corrosion (Edwards and Stroud, 1964). A pipe-analysis survey is run with a centralized probe that employs several coils (Bradshaw, 1976). This survey is reported to provide information on the thickness of casing penetrated by corrosion, whether the damage is internal or external, and isolated or circumferential. The electromagnetic-thickness survey measures the average casing thickness over an interval of about 0.6 m and can be used to monitor changes in thickness with time. Casing-inspection logging methods are summarized by Nielsen and Aller (1984)." EPA Web Archive: https://archive.epa.gov/esd/archive-geophysics/web/html/well_completion_logging.html

SED might provide additional future references.

SED adds the following reference, which is also included as an attachment.

1988.0101.SPWLA-1988-UU-NN

d. For each of the tools that YOU identify in response to Request 6(c), please describe YOUR understanding of the tool's efficacy in accurately identifying wall loss.

SED incorporates it's answer to question 6c by reference.

e. Identify the basis on which YOU contend that this alleged failure is a violation of Section 451.

The basis for this violation is provided in Section II.B of SED's opening testimony. See also the answer to question 6a.

7. YOU assert that SoCalGas did not "employ reasonable understanding of the groundwater depths relative to the surface casing shoe and production casing of well SS-25" prior to the drilling of two groundwater wells which were drilled for RCA purposes (OPENING TESTIMONY, page 39).

a. Please explain what YOU believe a "reasonable understanding of groundwater depths relative to the surface casing shoe and production casing of well SS-25" would have been.

SED objects to this question on the grounds that it mischaracterizes SED's testimony, and related role as the entity that is responsible for investigating the groundwater depths in the question. That is SoCalGas's (not SED's) mandated responsibility, pursuant to California Public Utilities Code Section 451. SED further objects to this question as unduly burdensome in that it requests SED to gather information related to the question that is or was in the control of SoCalGas, and analyze it to determine what type of understanding might have been adequate.

Despite the undue burden of this question, SED requires more time to answer this question, and may endeavor to provide an additional substantive answer.

SED requires an answer to Data Request 52 Question 7 as a condition precedent to providing a complete answer to this question. For reference, that question asks:

> Identify by well number all shallow water observation wells installed at the Aliso Canyon Storage Unit. For each well, provide:
>
> a. Well Number
> b. Installation record showing at least date drilled, depth of well, depth of water from surface.
> c. All data collected and recorded from these wells.
> d. One map showing location of shallow water wells at Aliso.

SED Data Request 52, Question 7 asked.

Identify by well number all shallow water observation wells installed at the Aliso Canyon Storage Unit. For each well, provide:
a. Well Number
b. Installation record showing at least date drilled, depth of well, depth of water from surface.

c. All data collected and recorded from these wells.
d. One map showing location of shallow water wells at Aliso.

SoCalGas responded to this question:

SoCalGas objects to this request as vague and ambiguous, particularly with respect to the phrase "shallow water observation wells," overly broad and unduly burdensome, and outside the scope of this proceeding as set forth in the Assigned Commissioner's Scoping Memo and Ruling dated September 26, 2019. Subject to and without waiving the foregoing objections, SoCalGas responds as follows. Prior to October 23, 2015, gas storage observation wells SS-5 and W3A were used to monitor pressure in the west and east field areas, respectively. Due to the incompleteness of this answer in failing to address subparts b, c, and d of Data Request 52, Question 7, SED is unable to answer this question at this time. Without knowing additional data that might have been available to SoCalGas, SED relies on the Blade Report for response to this question.

b. Identify the laws, rules, regulations, and/or industry standards, if any, that SED believes require SoCalGas to employ the understanding you explain in response to Request 7(a).

Despite, SED's objection to question 7a, SED understands this to be asking about the information from SED's testimony that is identified in the question, and answers accordingly. The rules include California Public Utilities Code Section 451, as identified in subsection a, which concludes on page 44 of SED opening testimony,

> By allowing groundwater to cause corrosion on the 7 inch and 11 ¾ inch casings on SS-25, SoCalGas violated Section 451. This violation begins on August 30, 1988, the date SoCalGas produced its Interoffice memo calling for inspections of the SS-25 casing, and continues to October 23, 2015, the beginning date of the incident.

The rules also include California Public Utilities Code Section 451, as identified in subsection b, which concludes on page 45 of SED opening testimony,

> SoCalGas's failure to assess the relationship between groundwater in and around the SS-25 wellsite, and the surface casing corrosion of that well on SS-25 constitute a violation of Section 451. This violation begins on August 30, 1988, the date SoCalGas produced its Interoffice Memo calling for inspections of the SS-25 casing, and continues to October 23, 2015, the beginning date of the incident.

To maintain its obligation to provide a safe system to protect employees and the public, SED expects SoCalGas will develop safe operation and maintenance standards and will implement them in the course of its normal business. These in-house procedures serve as a type of operating requirement for SoCalGas. As an example of SoCalGas not implementing its own standard, refer to SoCalGas' Company Operations Gas Standard for Pipeline Integrity - Design and Application of Cathodic Protection, SCG 186.002. This Standard was modified in 2000 to add cathodic protection for gas Storage, specifically well casings. Gas Storage management is charged with the responsibility of implementing the standard. Yet, 15 years later, well SS-25 failed from casing corrosion.

The NACE International standard practice provided in response to question 7c identifies procedures to determine the need for cathodic protection (CP) and the current requirements to achieve CP of well casings associated with oil and gas production and gas storage. It also outlines practices for the design and installation of CP systems and for their operation and maintenance. The purpose of this standard is to ensure more effective prevention of corrosion of well casings by making available reliable information about CP as it relates to well casings. This standard is intended for use by corrosion engineers in oil and gas production, especially those concerned with the CP of steel well casings. NEW REFERENCE: 2007.0101.NACE-SP0186-NN (Standard – first issued in 1986)

c. Identify and produce all DOCUMENTS, aside from the Blade Report, that support

SED's contention that SoCalGas did not employ a "reasonable understanding of the groundwater depths relative to the surface casing shoe and production casing of well SS-25" prior to the drilling of the two groundwater wells which were drilled for RCA purposes.

SED adds the following reference, which is provided as an attachments: SPE-3287-MS and SPE-17930-MS

d. Identify the basis on which YOU contend that this allegation is a violation of Section 451.

The basis for this violation is provided in Section II.B of SED's opening testimony. See also the answer to questions 7b and 7c. Also, see an additional new reference: 1978.0701.PETSOC-78-03-04_NN, SPE-17930-MS

8. YOU assert that SoCalGas did not "assess the relationship between groundwater in and around the SS-25 well site, and the surface casing corrosion of that well" (OPENING TESTIMONY, page 44).

SED objects to this question because it was already encompassed by all of question 7, and answered there. Therefore, SED incorporates by reference it's answers to question 7 in response to the questions for question 8.

a. Please identify the specific actions that YOU believe SoCalGas should have taken, prior to the SS-25 leak, to "assess" the relationship between the groundwater and the surface casing.

SED requires an answer to Data Request 52 Question 7 as a condition precedent to providing a complete answer to this question. For reference, that question asks:

> Identify by well number all shallow water observation wells installed at the Aliso Canyon Storage Unit. For each well, provide:
> a. Well Number
> b. Installation record showing at least date drilled, depth of well, depth of water from surface.
> c. All data collected and recorded from these wells.
> d. One map showing location of shallow water wells at Aliso.

See Response to Question 7a above.

b. Identify the laws, rules, regulations, or industry standards that required SoCalGas to assess the relationship between groundwater around the SS-25 well site, and the surface casing corrosion around that well.

The basis for this violation is provided in Section II.B of SED's opening testimony. See also the answer to question 7b, 7c, and 7d.

c. Identify the laws, rules, regulations, and/or industry standards, if any, that SED believes require SoCalGas to employ the specific actions you describe in response to Request 8(a).

The basis for this violation is provided in Section II.B of SED's opening testimony. See also the answer to question 8b.7(b).

d. Identify and produce all DOCUMENTS, aside from the Blade Report, that support SED's contention that SoCalGas did not "assess the relationship between groundwater in and around the SS-25 well site, and the surface casing corrosion of that well."

SED relies on the Blade Report for this violation. SED may update this answer at a later time.

See the answer to question 7b and c.

e. Identify the basis on which YOU contend that this allegation is a violation of Section 451.

The basis for this violation is provided in Section II.B of SED's opening testimony. See also the answer to question 8b.

9. YOU assert that SoCalGas had no systemic practices to protect surface casing strings against external corrosion and therefore did not employ "a proper understanding of the consequences of corroded surface casings and uncemented production casings" (OPENING TESTIMONY, page 45).

a. Please describe what YOU believe a "proper understanding of the consequences of corroded surface casings and uncemented production casings" would entail.

SED objects to this question on the grounds that it mischaracterizes SED's testimony, and related role as the entity that is responsible for investigating the information identified in the question. That is SoCalGas's (not SED's) mandated responsibility, pursuant to California Public Utilities Code Section 451. SED further objects to this question as unduly burdensome in that it requests SED to gather information related to the information identified in the question that is or was in the control of SoCalGas, and analyze it to determine what type of understanding might have been adequate.

Notwithstanding this objection, SED notes the follows: As discussed in certain scholarly articles, "Casing integrity and cement evaluation are not new concepts, in fact operators have evaluated reservoir and well integrity since the inception of underground storage a century ago." Pg.1, Sebastian Kamgang, et al & Baker Hughes Incorporated, "Innovative Cement and Casing

Corrosion Evaluation Technologies Provide Reliable Well Integrity Information In Natural Gas Storage Wells" 2017, SPWLA 58th Annual Logging Symposium, June 17-21, 2017

As an operator of multiple gas storage areas since as early as 1943, SoCalGas should by now have a thorough understanding of the consequences of corroded surface casings and uncemented production casings. A basic understanding would be that an uncemented casing that is exposed to soil and groundwater without any protection, such as cathodic protection, will corrode and eventually leak. A proper understanding of this concept would easily lead an engineer to the conclusion that some sort of protection is necessary to avoid the maintenance costs associated with repairs or replacement of a well. For additional information, SED adds the following references: SPE-2910-MS, SPE-3287-MS and SPE-17930-MS, NACE-SP0186-NN, 1959.0519.API-59-199_NNN, 1974.0701.SPE-4682-PA_NNN, 2007.0627.SPE-108906-MS_NNN, 2007.0924.SPE-108195-MS_NNN, 2007.1111.SPE-108698-MS_NNN

b. Identify the laws, rules, regulations, and/or industry standards, if any, that SED believes require SoCalGas to employ the understanding you explain in response to Request 9(a).

Despite, SED's objection to question 9a, SED understands this to be asking about the information from SED's testimony that is identified in the question, and answers accordingly. The rules include California Public Utilities Code Section 451, as identified on page 47 of SED's testimony, which states,

> SoCalGas violated Section 451 because it did not have systematic practice to protect surface casing strings against external corrosion, and because it did not understand the consequences of corroded surface casings and uncemented production casings. This violation begins on August 30, 1988, the date SoCalGas produced its Interoffice Memo calling for inspections of the SS-25 casing, and continues to October 23, 2015, the beginning date of the incident.

Good completion practices include the use of drilling mud with an alkaline Ph; the circulation of cement for the entire length of the casing; use of similar metals in all parts of the structure; and the insulation of the well line from the casing. See page 2, 1970.0101.SPE-2910-MS (attached). See also 7.b

c. Identify and produce all DOCUMENTS, aside from the Blade Report, that support SED's contention that SoCalGas failed to employ "a proper understanding of the consequences of surface casing and uncemented production casings."

See response to 9a.

d. Identify the basis on which YOU contend that this allegation is a violation of Section 451.

The basis for this violation is provided in Section II.B of SED's opening testimony. See also the answer to questions 9a and 9b.

10. YOU assert that SoCalGas did not understand "the extent and consequences of the corrosion in other ALISO CANYON Storage wells" because of its alleged failure to investigate previous failures (OPENING TESTIMONY, page 7).

SED objects to this question because it was asked and answered. This question encompasses those that were asked already as part of this data request. See in particular, questions 1 through 6 and question 10 of this data request. This objection applies throughout the data response, and includes references to other data responses to show certain applicable data responses.

a. Please describe what YOU believe SoCalGas should have done to understand the "extent and consequences of the corrosion in other ALISO CANYON storage wells."

See responses to 6c and 9a

b. Identify the laws, rules, regulations, and/or industry standards, if any, that SED believes require SoCalGas to engage in the actions YOU explain in response to Request 10(a).

SED objects to this question because it was asked and answered.

c. Identify and produce all DOCUMENTS, aside from the Blade Report, that support SED's contention that SoCalGas failed to understand "the extent and consequences of the corrosion in other ALISO CANYON storage wells."

See response to 6c and 2012.1111.SPE-161983-MS_NNN

d. Identify the basis on which YOU contend that this allegation is a violation of Section 451.

The basis for this violation is provided in Section II.B of SED's opening testimony. See also the answer to questions 9a and 9b.

11. YOU assert that SoCalGas "did not attempt to understand causes of the leaks at 60 wells" at ALISO CANYON (OPENING TESTIMONY, page 11).

a. Do YOU contend that SoCalGas conducted no investigation at all for the leaks mentioned above?

SoCalGas has represented to the Commission that, “The casing leaks, as SoCalGas understands them to be identified in the Blade Report, were successfully assessed and addressed by SoCalGas and, where appropriate, further investigation was performed. In order to remediate any leaks, SoCalGas necessarily had to analyze and diagnose the issue, and then implement a fix, as needed.” SED reserves the right to re-visit this issue once Blade has had an opportunity to address SoCalGas’s statement, and pending SoCalGas providing underlying facts to show the veracity of this statement.

Upon further review, SoCalGas did a model SIMP study to determine the condition of the casing on Frew 2 in 2014. SED reserves the right to provide further updates to this answer in the future.

b. Identify and produce all DOCUMENTS, aside from the Blade Report, that support SED’s response to Request 11(a).

See response to question 11a.

c. What do YOU contend constitutes a “leak”?

A leak is any failure of the well integrity that results in a release of gas to the surrounding reservoir soil, groundwater and/or to the atmosphere. Leaks include those leaks of 60 wells at Aliso Canyon, as identified by the Blade Report at page 4, as mentioned in footnote 42 of SED's opening testimony. See also page 9 of SED's testimony, which says,

> To avoid double counting violations, SED assumes that the 60 leaks identified before the Aliso Canyon incident included the six blowouts and parted casings identified above. As such, the remaining 54 leaks that went without investigation should constitute a separate set of up to 54 violations. At the latest, these violations began on October 22, 2015, the last possible date before the incident on October 23, 2015.

d. Please describe what actions YOU believe are necessary for a reasonable investigation of a leak.

SED objects to this question in that it mischaracterizes SED’s testimony, and related role as the entity that is responsible for investigating leaks on SoCalGas’s system. That is SoCalGas’s (not SED’s) mandated responsibility, pursuant to California Public Utilities Code Section 451. SED reserves the right to investigate and audit SoCalGas for safety related purposes.

SED also objects to this question as vague and overly broad. This question would have SED provide an up front commitment to what constitutes a necessary investigation of a leak for every instance without having the facts associated with a given leak, thereby potentially compromising the ability of SED's investigators to do their work when investigating leaks for safety related purposes.

Notwithstanding these objections, please refer to the responses to 6c, 9a and 10c

Please also see Blade's Response to SED Data Request 49, Questions 3 through 5. For context, these responses are replicated here.

2.3 Question 3

Does Blade agree with the statement that, "The Blade Report fails to recognize, however, that a 'formal investigation' of the type Blade appears to envision would likely entail a level of examination that would not be feasible for an active well, nor necessary. While Blade was able to cut, extract, and thoroughly examine the casing at well SS-25 because there were plans to abandon the well, it is not feasible for SoCalGas to perform the same level of failure analysis on active gas storage wells."

2.3.1 Response 3

Blade disagrees with the statement.

2.4 Question 4

If Blade agrees with the statement in question 3, please explain why.

2.4.1 Response 4

See Response 5.

2.5 Question 5

If Blade disagrees with any portion or all of the statement in question 3, please explain why it disagrees.

2.5.1 Response 5

Solution 6: Conduct a Casing Failure Analysis from the Blade Main Report, Section 5.3.1, Page 232, is replicated here for reference.

Solution 6: Conduct a Casing Failure Analysis

Despite numerous casing failures, no data were provided to indicate that failure causes were investigated. Casing failures need to be formally investigated so that their causes are identified and their implications are understood. Understanding and interpreting failures are critical to defining the propensity or risk of such failures field wide. Such analysis is an important part of any risk assessment. The cause may be straightforward, well specific, and easily mitigated. However, if the cause appears to systemic, or the potential consequences are serious, then a more comprehensive investigation is needed to evaluate the potential risks to other wells in the field so that the appropriate mitigation steps are taken. For example, failure investigation of casing OD corrosion in another well might have directed attention to SS-25 and other similar wells. Running an inner string or plugging a well are valid mitigations, but prior to such actions, the cause of the casing leak or failure should be understood. **The type of investigation should be commensurate with the risk and consequence of the failure, and should be part of the well integrity management system.**

As stated in Solution 6, the last sentence; "The type of investigation should be commensurate with the

risk and consequence of the failure, and should be part of the well integrity management system." It is understood that all failures cannot be treated like SS-25, nor should they. The level of investigation depends on many things including the depth of the failure. It may not be feasible, practical, or necessary, to recover production casing from a deep leak. However, inspection and diagnostic tools are available to determine the nature of the failure, such as, a hole, corrosion—internal or external over a large or small area, location of a failure—pipe body or connection, etc. Such data should be integrated and analyzed to assess the possible causes and develop some hypothesis that can be used to evaluate other wells with failures. Once the failure has been evaluated and understood, the appropriate steps can be taken to determine the disposition of the well. The well can be repaired (inner strings, etc.) or plugged and abandoned if not repairable or if the well is no longer needed. SoCalGas did repair wells or plugged and abandoned wells after the failures were identified.

e. Identify the laws, rules, regulations, and/or industry standards, if any, that YOU believe require SoCalGas to engage in the actions YOU describe in response to Request 11(d).

Despite, SED's objection to question 11d, SED understands this to be asking about the information from SED's testimony that is identified in the question, and answers accordingly.

SED's testimony on pages 8 and 9 state in part,

SED views SoCalGas's failure to investigate or analyze the failures or root causes of casing leaks, parted casings, or other failure events as separate violations of Section 451, as follows. . .

> To avoid double counting violations, SED assumes that the 60 leaks identified before the Aliso Canyon incident included the six blowouts and parted casings identified above. As such, the remaining 54 leaks that went without investigation should constitute a separate set of up to 54 violations. At the latest, these violations began on October 22, 2015, the last possible date before the incident on October 23, 2015.

In addition, See API RP 585, as identified in Blade's data response to SED Data Request 49, Question 6, which is replicated below for context.

2.6 Question 6
With regards to the statement, that, "a 'formal investigation' of the type Blade appears to envision would likely entail a level of examination that would not be feasible for an active well. . .", what levels of
examination are feasible for an active well that SoCalGas could have performed in Blade's opinion?

2.6.1 Response 6

This is addressed by Solution 7: Regulations Should Require a Level 1 (Per API RP 585) Analysis of All Failures in the Blade Main Report, Section 5.3.1, Page 232, replicated here for reference.

Solution 7: Regulations Should Require a Level 1 (Per API RP 585) Analysis of All Failures API RP 585 Pressure Equipment Integrity Incident Investigation, discusses failure investigation of pressure equipment [2]. The Aliso Canyon wells are a form of complex pressure vessels. A Level 1 type analysis of failures, as a minimum requirement, will identify the immediate causes of the failures or near misses and allow operators to understand the implications, if any.

Figure 8 shows the different levels of investigation as discussed in RP 585. A Level 1 investigation may be appropriate for most casing failures and can be done quickly with no disruption to field operations. API RP 585 was developed for Pressure Equipment Integrity Incident Investigation; however, Blade presents this as an option that could be applied to Gas Storage Well Integrity Management.

	Level 1 Investigations	Level 2 Investigations	Level 3 Investigations
Incident Characteristics	— Unexpected condition or damage found that if it had been allowed to progress would have led to loss of containment before the next scheduled outage or inspection interval. — Discovered PEI damage significantly beyond expectation but with no loss of containment or unit shutdown. — Small leaks (other than environmental fugitive emissions) from pressure equipment or joints that were easily contained. — Typically no fire, significant toxic release, injuries, or environmental damage would occur in a Level 1 incident.	— Leak from pressure equipment that resulted in or could have resulted in localized equipment damage, small to medium size release quantity, or small safety or environmental damage. — Unexpected pressure equipment failure from damage mechanisms or structural deterioration. — Unexpected pressure equipment damage or associated structural damage discovered that required equipment or unit shut down or immediate mitigation. — Repetitive Level 1 type characteristics in the same process or system.	Leak or rupture from pressure equipment that resulted in or could have resulted in significant process safety incident or environmental damage, equipment damage, large release quantity, or production loss.
Investigation Characteristics	Investigate using less structured analysis tools such as "What If" or "5-Whys." Uses evidence, judgment, and experience to identify causes.	Investigate using company or department causal factor identification or logic trees, seeking probable contributing and root causes.	Investigate using company structured root cause analysis (RCA) seeking to determine the deepest management system and cultural causes.
Team Makeup Recommended	Investigated by the PEI personnel from the affected area and trained in simple investigation techniques. Can be investigated by one person, possibly two. Involve subject-matter experts (SMEs) as needed.	Leader would be someone from the affected area trained in investigation techniques. Team members would include one to three others of different disciplines from the area; include at least one PEI person on the team. Involve SMEs as needed.	Leader would be someone trained in structured RCA and from another area of the plant or another business unit. There would be at least three team members and possibly from different disciplines or groups, such as inspection, operations, process engineering, maintenance, or process safety. Appropriate SMEs should be included on the team.
Initiation	Within a few days.	Begin investigation as soon as practical (e.g. 1 to 2 days).	Begin freezing and collecting evidence as soon as practical (e.g. within a few hours).
Sponsorship	Supervisor of investigator (First Line Supervisor).	Department Head level (Second Line Supervisor).	Management with overall responsibility for Safety Health Environment for the site.

Figure 8: API 585 Inspection Levels

Failed casing in an active well can be analyzed using casing wall thickness inspection, downhole camera, and other diagnostic tools as discussed in Section 2.2.1 Response 2. This may provide data that can be used to interpret causes for the casing failure.

f. Identify the basis on which YOU contend that this allegation is a violation of Section 451.

The basis for this violation is provided in Section II.B of SED's opening testimony. See also the answers to the other parts of Question 11.

12. YOU assert that the Aliso Canyon storage wells had "numerous casing leaks" and assert

that these leaks “may have been relevant to the conditions at SS-25.” (OPENING TESTIMONY, page 7).

a. Describe how each of the alleged “numerous casing leaks” were “relevant to the conditions at SS-25.”

SED objects to the request to describe how each of the alleged numerous casing leaks were relevant to the conditions at SS-25 as unduly burdensome. SED further objects to this question as mischaracterizing SED's testimony. SED stated that the leaks "may have been relevant to the conditions at SS-25", not that they "were" relevant. SED answers this question with the understanding that SoCalGas meant to replace the term "were" with "may have been".

The numerous casing leaks at the Aliso Canyon storage wells may have been indicators that other wells at the storage facility, including well SS-25, were also likely to experience leaks, as well as threats related to leaks, including the documented corrosion that the casing of well SS-25 had. While the Aliso field is geologically complex, except for recently drilled wells, all of the wells were constructed in the same time period of similar materials and are exposed to similar environmental and gas quality conditions. Specifically, the inclusion of SS-25 with other wells on a 1988 list for evaluation and the 2014 finding in the SIMP study of FREW 2 that the casing had numerous leaks, should have been sufficient information to cause SoCalGas to look more closely at SS-25 for corrosion or other causes of leaks.

b. Identify and produce all DOCUMENTS, aside from the Blade Report, that support SED’s contention that the “numerous casing leaks” “may have been relevant to the conditions at SS-25.”

SED relies on the Blade Report for this violation. SED may update this answer at a later time.

In the 2014 evaluation of FREW 2, there was clear evidence of external corrosion which should have raised an immediate concern for other wells exposed to similar conditions. Corrosion was extensive, including 82% loss with 0% remaining strength. See SoCalGas’s Data Response to SED Data Request 25.

SED requires an answer to Data Request 52 Question 9 as a condition precedent to providing a complete answer to this question. For reference, that question asks:

> In addition to the SIMP Model Studies performed in 2014 on FREW 2, identify all other similar studies performed on other Aliso wells prior to October 23, 2015. For each study identified, provide a complete copy of the resulting report(s) that present log interpretations and results. Each report should be provided in separate, searchable pdf document(s).

In Data Request 52, Question 9, SED asked,

In addition to the SIMP Model Studies performed in 2014 on FREW 2, identify all other similar studies performed on other Aliso wells prior to October 23, 2015. For each study identified, provide a complete copy of the resulting report(s) that present log interpretations and results. Each report should be provided in separate, searchable pdf document(s).

In response, to this question, SoCalGas stated,

SoCalGas objects to this request as vague and ambiguous, particularly with respect to the phrase "SIMP Model Studies" and term "similar," overly broad, and unduly burdensome. Subject to and without waiving the foregoing objections, SoCalGas responds as follows. SoCalGas interprets this request to seek information about the SIMP Pilot Project. Please refer to SoCalGas' response to SED Data Request 25 ("DR-25") dated August 14, 2018. Rather than providing an answer to a direct specific question, this is a data dump, referring to over 1500 documents. It was during SED's review of SoCalGas' response to DR 25 that the SIMP Model Study report of corrosion on well FREW 2 was found. In an ongoing effort to give SoCalGas credit for all investigations into well corrosion and anomalies, SED asked for similar reports. Due to the non-responsive answer of SoCalGas, SED must assume that SoCalGas performed no other studies of wells prior to 2015 that would have identified corrosion or anomalies in well tubings or casings. Therefore, SED has no further comments on this issue at this time.

13. Do YOU contend that SoCalGas has or had authority to compel Daniel Clayton of BOOTS AND COOTS to appear for an examination under oath in response to the SUBPOENAS? If so, state all facts, reasons, and grounds upon which YOU base YOUR contention.

SED objects to this question as vague in that it does not identify the page number or passage of SED's testimony that it is questioning. SED further objects to this question to the extent that it calls for legal conclusion with regards to SoCalGas's authority to compel Mr. Clayton to appear for examination under oath.

SED further objects to this question on the grounds that SoCalGas has asked SED to provide a legal justification for one of its asserted violations, which SoCalGas agreed it would not do in the pre-hearing conference.
SoCalGas's position was that SED should identify alleged violations with specificity in opening testimony. SED identified a concern that SoCalGas not cross-examine SED's witnesses as lawyers for concluding that there was a violation, and SoCalGas voiced no objection to this concern. SED has now proceeded in reliance on SoCalGas's assurance on the record that it would not cross-examine SED's witnesses for identifying the legal justifications for alleged violations in testimony, but this question does exactly that. For context and reference, SED quotes the pertinent portion of the transcript here.1
The next question concerns the deadline for SED to submit alleged violations and the factual and legal justifications for each alleged violation.· My question is

whether it would be reasonable to set a deadline of opening testimony for SED to submit alleged violations, and the factual justifications for each alleged violation, and set a deadline of opening briefs for SED to submit the legal justifications for its alleged violations?
Would any party like to respond to my question?· SoCalGas.
MR. STODDARD:· SoCalGas's position on this is that SED should identify the alleged violations with specificity in its opening testimony sooner, if possible; but in its opening testimony would be acceptable to SoCalGas as we had proposed in our prehearing conference statement.
MR. SHER:· Your Honor, SED would not necessarily be opposed to such if SoCalGas agreed now that it would not waste time cross-examining SED's witness as to their legal basis for tying violations to code sections, et cetera.
ALJ KENNEY:· Does SoCalGas have a response at this time?
MR. STODDARD:· SoCalGas is not going to waive any rights to cross-examination. Although, I would ask for clarification what exactly is meant by "legal basis" here?
MR. SHER:· The way your Honor set this out is that the violations would be set forth in the opening, and then the legal issues would be discussed in the briefing. To the degree -- it is highly unlikely that SED's witness will be a lawyer.· So we don't want SoCalGas, if we are going to do this all in our opening testimony, to cross-examine the witness as to their legal basis for concluding that this is a violation, for example, of 451.

MR. STODDARD:· SoCalGas does not object to that.
ALJ KENNEY:· Thank you.

[1] See I.19-06-016, Pre-hearing conference transcripts, pp. 43 : 11 to 44 : 28.

14. Do YOU contend that SoCalGas has or had authority to compel Mike Baggett of BOOTS AND COOTS to appear for an examination under oath in response to the SUBPOENAS? If so, state all facts, reasons, and grounds upon which YOU base YOUR contention.

SED objects to this question as vague in that it does not identify the page number or passage of SED's testimony that it is questioning. SED further objects to this question to the extent that it calls for legal conclusion with regards to SoCalGas's authority to compel Mr. Baggett to appear for examination under oath. SED incorporates the entirety of its objection on legal conclusion grounds in response to question 13 here.

15. Do YOU contend that SoCalGas was legally obligated to include a term in its STANDARD SERVICES AGREEMENT with BOOTS AND COOTS that required BOOTS AND COOTS to subject itself to the same provisions to cooperate with SED's pre-formal investigation that SoCalGas was required to follow? If so, state all facts, reasons, and grounds upon which YOU base YOUR contention.

SED objects to this question as vague in that it does not identify the page number or passage of SED's testimony that it is questioning. SED further objects to this question to the extent that it calls for legal conclusion with regards to the legal obligations that SoCalGas had to include one or more terms in its STANDARD SERVICES AGREEMENT with BOOTS AND COOTS.
SED incorporates the entirety of its objection on legal conclusion grounds in response to question 13 here.

16. Do YOU contend that SoCalGas was legally obligated to include a term in its STANDARD SERVICES AGREEMENT with BOOTS AND COOTS that required BOOTS AND COOTS to respond to investigation-related inquiries from SED and/or Blade? If so, state all facts, reasons, and grounds upon which YOU base YOUR contention.

SED objects to this question as vague in that it does not identify the page number or passage of SED's testimony that it is questioning. SED further objects to this question in that it calls for a legal conclusion, asking for SED's views as to legal obligations of SoCalGas and requirements of Boots and Coots.
SED incorporates the entirety of its objection on legal conclusion grounds in response to question 13 here.

17. Do YOU contend that YOU have or had jurisdiction over the contractors that SoCalGas engaged to perform services in connection with responding to the ALISO CANYON leak? If not, do YOU contend that including the provision noted on page 58 of the OPENING TESTIMONY (i.e., a provision that required the contractor "to subject itself

to the same provisions to cooperate with SED's pre-formal investigation that SoCalGas itself was required to follow") would have conferred upon YOU such jurisdiction over SoCalGas' contractors?

SED objects to this question in that it calls for a legal conclusion with respect to whether SED has had or does have jurisdiction over SoCalGas's contractors.
SED incorporates the entirety of its objection on legal conclusion grounds in response to question 13 here.

18. Identify all actions YOU believe SoCalGas should have taken to compel BOOTS AND COOTS personnel to comply with YOUR SUBPOENAS.

SED objects to this question in that it calls for a legal conclusion with respect to steps SoCalGas should have taken to compel Boots and Coots personnel to comply with SED's subpoenas.
SED incorporates the entirety of its objection on legal conclusion grounds in response to question 13 here.

19. Identify and produce all DOCUMENTS evidencing service of YOUR SUBPOENAS on BOOTS AND COOTS.

SED served subpoenas on SoCalGas to produce Boots and Coots, but not on Boots and Coots directly.

20. Identify all actions YOU took to compel BOOTS AND COOTS personnel to comply with YOUR SUBPOENAS.

SED served SoCalGas with subpoenas to produce Boots and Coots, but did not subpoena Boots and Coots personnel directly.

21. Identify the basis on which SED contends that the lack of terms in the STANDARD SERVICES AGREEMENT as discussed in Requests 15 and 16 is a violation of Section 451.

SED objects to this question as ambiguous and vague in that it does not identify the page number or passage of SED's opening testimony to which it is referring. SED further objects to this question as vague and ambiguous in that it does not clarify what "Requests 15 and 16" means, and does not clarify the passages to which the question is referring. If SED receives clarification, SED reserves the right to object to this question to the extent It calls on SED to make a legal conclusion. SED incorporates the entirety of its objection on legal conclusion grounds in response to question 13 here.

22. Produce all DOCUMENTS reflecting COMMUNICATIONS between YOU and BOOTS AND COOTS.

SED objects to this question as unduly burdensome on the grounds that it asks for extensive communications that could take extensive man hours to prove that there is not a single communication that SED has not turned over. Also because of undue burden on SED, SED does not understand this request to include those documents that SoCalGas forwarded from Boots and Coots to SED, or from SED to Boots and Coots. SED further objects to this request as vague and overly broad, asking for all communications between SED and Boots and Coots; not merely those that are within the scope of this proceeding.

Notwithstanding these objections, to the best of SED's knowledge at this time, SED has already produced to SoCalGas all documents reflecting communications between SED and Boots and Coots related to the instant proceeding. These include the Examination Under Oath transcripts of Mr. Danny Walzel and Mr. Mike Kopecky.

23. YOU assert on page 70 of YOUR OPENING TESTIMONY that "Data in the SS-25 file reveals an ongoing detection of leaks at the bottom of the well." Identify the specific data that YOU contend reveals an ongoing detection of leaks.

The specific data is provided In the Bates numbers shown in footnote 443 of SED's opening testimony; SS-25 Well File, Supporting Attachments SED 01774-01778, 01804-01810,[2] and 01894-01895.

24. YOU assert on page 72 of YOUR OPENING TESTIMONY that "The Well File for SS-25 is not kept in any particular order. Typically, such a file would be maintained in chronological order." State all facts, reasons, and grounds upon which YOU base YOUR assertion that gas storage well files are typically maintained in chronological order.

This statement is based on the condition of the well file provided in response to SED DR 1, which was a series of single page Pdf documents. SED assumes this first rendition of the file was a perfect copy of the files in the order in which they appeared in the SoCalGas well file on or about October 23, 2015. If this assumption is correct, the well file lacked any discernable order. And in comparing the SS-25 file with the similarly produced SS-25A and 25B well files, there appears to be documents missing from the SS-25 well file, such as Inter-Office memos that might address the ongoing indications of one or more leaks on temperature surveys and any proposed actions or maintenance actions. The SS-25 well file is also missing basic geologic and reservoir data that would normally be acquired during drilling or logging.

SED requires more time to answer this question, and reserves the right to provide an additional substantive answer.

25. YOU assert on page 74 of YOUR OPENING TESTIMONY that "SoCalGas records do not show operating records that would be reasonable to keep and mirror typical record

[2] SED's opening testimony states 018010. This is a typo, and is corrected to say 01810.

retention policies in the industry."

a. Identify all "record retention policies" that you contend are typical in the gas storage industry.

SED objects to this question as unduly burdensome. Despite the undue burden of this question, SED ~~requires more time to answer this question, and reserves the right to provide an additional substantive answer.~~

SoCalGas has a record retention policy dated November 30, 2013 that identifies the gas storage records to be kept for the life of the asset plus 5 years. See AC_CPUC_SED_DR_17_000024-25. To date, SoCalGas has not demonstrated to a reasonable degree that it kept all of these records for the Aliso Canyon Storage Facility. Records produced fail to show any organization such that the records would be readily accessible to those who need to access them, especially in the event of an emergency.

Examples of other industry record retention policies are provided as attachments. These policies include references to governing laws and regulations, which SoCalGas can obtain separately through its own library or law office.

1986.0601.GTR0004210_SP_210.4-4_Records_retention.pdf (Redacted)
GasTransmissionSystemRecordsOII_DR_CPUC_023-Q26Atch08_REDACTED.pdf
Pages 34-35.PG&E.P2-2-Guide.to.Record.Retention-2003.pdf (Redacted)

b. Did SED ever conduct an audit of SoCalGas relating to whether SoCalGas had record-keeping procedures that were "reasonable" or "mirror[ed] typical retention policies in the industry."

SED objects to this question as unduly burdensome. SoCalGas is the subject of all SED audits identified in the question, and has the information regarding whether it was the subject of any such audits. SED reminds SoCalGas to avoid wasting limited SED staff time with questions to which SoCalGas does or should demonstrably have the answer.

c. Produce all DOCUMENTS regarding "typical record retention policies in the industry."

SED objects to this question as unduly burdensome in asking for SED to produce all such typical record retention policies in the industry because SoCalGas should also have such information. Despite the undue burden of this question, SED ~~requires more time to answer this question, and reserves the right to provide an additional substantive answer.~~

See also attached in response to 25.a.

26. YOU assert on page 68 of YOUR OPENING TESTIMONY that "This failure to maintain basic records led to the inability to maintain wells in safe conditions and to supply critical operating data in response to emergencies."

a. Identify all instances in which YOU contend failure to maintain basic records by SoCalGas "led to the inability to maintain wells in safe conditions." For each such instance, identify the relevant well and record.

SED requires an answer to Data Request 52 Questions 1, 3, 4, 5, 6, 7, 8 and 9 as a condition precedent to providing a complete answer to this question.

b. Identify all instances in which YOU contend failure to maintain basic records by SoCalGas "led to the inability… to supply critical operating data in response to emergencies." For each such instance, identify the relevant well and record.

SED objects to this question as unduly burdensome in that it requests SED to gather information related to the question that is or was in the control of SoCalGas, and analyze it to determine what type of whether failure to maintain basic records by SoCalGas led to the inabilities identified in the question.

Despite the undue burden of this question, SED replies: Please refer to page 131 of the Blade Main Report, March 16, 2019, where Blade Identifies the difference between its determination of the Bottom Hole Pressure ("IPR") compared to the significantly lower pressure SoCalGas gave to DOGGR and the national laboratory for well kill calculations. For further analysis of the results of this difference, see the Blade Report. Records used by Blade for development of the BHP are discussed on pages 128-130 of the Blade Main Report. This discussion points out the problems with some historical data provided to Blade. But, at the basic level, SoCalGas had no current record of the BHP for SS-25, or for the reservoir when Well-SS-25 failed.

Supplementing the above statement. SoCalGas severely underestimated the Reservoir Pressure. (See Blade Vol 3. SS-25 Transient Well Kill Analysis, pp. 10 and 16.) In addition, SoCalGas used an incorrect gas flow of 30 MMscf/D, which should have been in the range of 80 to 93 MMscf/D. SoCalGas' own historical data showed well flow in excess of 80 MMScf/D. (see Blade Vol. 3 SS-25 Transient Well Kill Analysis, p. 37.) These Incorrect figures were apparently used by SoCalGas and Boot & Coots in developing kill procedures that failed. While SoCalGas did not produce evidence of utilizing models prior to kill attempt 7, SED assumes SoCalGas and its contractors, at a minimum, performed calculations to determine the ppg of fluid and pump pressures it would use in each kill attempt. Reservoir pressure, bottom hole pressure and well flow are critical factors in making such calculations. Underestimating these numbers led to repeated well kill failures. A responsible gas stororage operator should have current records that accurately reflect these critical operating data and those records should be readily available to engineering and operating personnel. SoCalGas failed in this respect, creating an

unsafe situation in which conditions at Well SS-25 could not be fully controlled by personnel and where an estimated 120,000 metric tons of methane were released into the atmosphere from the end of October 2015 to early February 2016.

SED requires an answer to Data Request 52 Questions 1, 3, 4, 5, 6, 7, 8 and 9 as a condition precedent to providing a complete answer to this question.

SED Data Request 52 Question 1 asked:

Related to AC_CPUC_0014712-20175 identify by AC.CPUC file number each Cathodic Protection Work Order Report that shows readings on a gas well casing.

SoCalGas's response to SED Data Request 52 Question 1 was non-responsive,

SoCalGas objects to this request on the grounds that it is vague and ambiguous, particularly with respect to the term "readings" and phrase "gas well casing." SoCalGas further objects to this request as overly broad and imposing an undue burden under Rule 10.1 of the Commission's Rules of Practice and Procedure to the extent it seeks to require SoCalGas to search through documents previously provided to SED and in SED's possession.

SED is unable to discern from SoCalGas's answer which exact documents SoCalGas means to be responsive to the question.

SED Data Request 52 Question 3 asked:

Related to AC_CPUC_SED_KITSON_0003008, provide all forms 3466 "Reporting of Gas Blown to Atmosphere" that reported the amount(s) of gas blown to atmosphere associated with the SS25 leak.

"SoCalGas's response to SED Data Request 52 Question 3 was non-responsive and incomplete, stating,

SoCalGas objects to this request to the extent it is vague and ambiguous and seeks information that is outside the scope of this proceeding as set forth in the Assigned Commissioner's Scoping Memo and Ruling dated September 26, 2019. Subject to and without waiving the foregoing objections, SoCalGas responds as follows. The amount of gas blown to atmosphere associated with the SS25 leak was not reported through Form 3466 "Reporting Gas Blown to Atmosphere."

SED Data Request 52 Question 4 asked:
Also related to AC_CPUC_SED_KITSON_0003008, provide all completed forms (please include an ID form number(s) or database name or names) that report the amount of oil discharged to the atmosphere and the amount(s) captured as liquid during the 2015-2016 SS-25 leak.

SoCalGas's response to SED Data Request 52 Question 4 was non-responsive and incomplete, stating,

SoCalGas objects to this request to the extent it is vague and ambiguous and seeks

information that is outside the scope of this proceeding as set forth in the Assigned Commissioner's Scoping Memo and Ruling dated September 26, 2019. Subject to and without waiving the foregoing objections, SoCalGas responds as follows. Form 3466 "Reporting Gas Blown to Atmosphere" referenced in AC_CPUC_KITSON_0003008 does not contemplate reporting oil discharge volumes.

SED Data Request 52 Question 5 asked:

Related to AC_CPUC_SED_DR17_0000163, provide (or identify DR response and bates numbers) records referenced in the "5.1 Records" section of Standard 224.02 for Wells SS-25, SS-25A and SS-25B.

SoCalGas's Response to Data Request 52 Question 5 answered:

SoCalGas objects to this request as overly broad, unduly burdensome, and outside the scope of this proceeding as set forth in the Assigned Commissioner's Scoping Memo and Ruling dated September 26, 2019. SoCalGas further objects to this request for failing to provide a defined time period to which SoCalGas may tailor its response. Subject to and without waiving the foregoing objections, SoCalGas responds as follows. SoCalGas interprets this request to seek information for the 3 months preceding October 23, 2015. Please see electronic documents with Bates range:

I1906016_SCG_SED_DR_52_0000001 through I1906016_SCG_SED_DR_52_0000036. Additional documents will be provided in an upcoming supplement to this response.

Due to the incomplete nature of this response, SED is unable to analyze it and answer the question at this time.

SED Data Request 52, Question 6 asked:

Also related to AC_CPUC_SED_DR17_0000163, provide daily records for the 3 months preceding October 23, 2015 and ALL records of sacrificial probes, including probe installation, failure and replacement.

SoCalGas's response to Data Request 52, Question 6 answered:

SoCalGas objects to this request as overly broad, unduly burdensome, and outside the scope of this proceeding as set forth in the Assigned Commissioner's Scoping Memo and Ruling dated September 26, 2019. Subject to and without waiving the foregoing objections, SoCalGas responds as follows. SoCalGas interprets this request to seek information for wells SS-25, SS25A, and SS-25B. Please refer to Response 5.

Due to the incomplete nature of this response, SED is unable to analyze it and answer the question at this time.

SED Data Request 52, Question 7 asked.

Identify by well number all shallow water observation wells installed at the Aliso Canyon Storage Unit. For each well, provide:
a. Well Number
b. Installation record showing at least date drilled, depth of well, depth of water from surface.
c. All data collected and recorded from these wells.
d. One map showing location of shallow water wells at Aliso.

SoCalGas responded to this question:

SoCalGas objects to this request as vague and ambiguous, particularly with respect to the phrase "shallow water observation wells," overly broad and unduly burdensome, and outside the scope of this proceeding as set forth in the Assigned Commissioner's Scoping Memo and Ruling dated September 26, 2019. Subject to and without waiving the foregoing objections, SoCalGas responds as follows. Prior to October 23, 2015, gas storage observation wells SS-5 and W3A were used to monitor pressure in the west and east field areas, respectively. Due to the incompleteness of this answer in failing to address subparts b, c, and d of Data Request 52, Question 7, SED is unable to answer this question at this time.

SED Data Request 52, Question 8 asked:

Related to AC_CPUC_SED_DR17_0000185, provide all records referenced in Section 5.1 collected, calculated and plotted during 2014-2015 for Aliso Canyon Storage Unit. Please state what form these records are kept in and where they are stored.

SoCalGas responded to Data Request 52, Question 8 as follows:

SoCalGas objects to this request as vague and ambiguous, particularly with respect to the phrase "Aliso Canyon Storage Unit," overly broad, and unduly burdensome. Subject to and without waiving the foregoing objections, SoCalGas responds as follows. SoCalGas interprets this request to seek information about the Aliso Canyon Gas Storage Field. Please see electronic document with Bates range: I1906016_SCG_SED_DR_52_0000037.

SED is unclear how this document responds to the question asked. Therefore, SED assumes from this response that SoCalGas is not maintaining the records per its own Standard.

In Data Request 52, Question 9, SED asked,

In addition to the SIMP Model Studies performed in 2014 on FREW 2, identify all other similar studies performed on other Aliso wells prior to October 23, 2015. For each study identified, provide a complete copy of the resulting report(s) that present log

interpretations and results. Each report should be provided in separate, searchable pdf document(s).

In response, to this question, SoCalGas stated,

SoCalGas objects to this request as vague and ambiguous, particularly with respect to the phrase "SIMP Model Studies" and term "similar," overly broad, and unduly burdensome. Subject to and without waiving the foregoing objections, SoCalGas responds as follows. SoCalGas interprets this request to seek information about the SIMP Pilot Project. Please refer to SoCalGas' response to SED Data Request 25 ("DR-25") dated August 14, 2018. The request is for records of Surface Pressure taken during shut-in, calculations and Plots. The documents provided may contain some of the information, but do not appear to fit the Records requirement in their Standard.

Rather than providing an answer to a direct specific question, DR 25 response is a data dump, of over 1500 documents in the middle of which SED found the SIMP Model Study report. Due to the non-responsive answer of SoCalGas, SED is unable to provide a further answer to this question at this time.

SED had asked the questions in DR 52 to gain a clearer understanding of how SoCalGas keeps records. Because SoCalGas did not provide any substantive responses, SED will assume SoCalGas either does not have responsive documents or, if it does, the documents cannot be found due to poor recordkeeping practices.

c. Identify the basis on which YOU contend that this alleged failure is a violation of Section 451.

SED objects to this question on the grounds that it mischaracterizes SED's testimony. SED does not use this point as the violation of Section 451. Instead, the violations are identified at the end of the section in which this sentence is found. Namely, the recordkeeping related violations in this section are articulated on SED opening testimony page 75, and state,

> In conclusion, SoCalGas' imprudent and unreasonable record keeping practices violated Section 451 three times; once for well SS-25, a second time for well SS-25A, and a third time for well SS-25B. The violation associated with well SS-25 begins June 6, 1973, the date that SoCalGas hydrotested their gas conversion of well SS-25. The violation associated with well SS-25A began December 7, 1972, the date that well SS-25A became operational according to DOGGR records. The violation associated with well SS-25B began October 29, 1973, the date that well SS-25B became operational according to DOGGR records.
>
> Each of these three violations end on October 23, 2015, as safety records in Well Files SS-25, SS-25A and SS-25B appeared to be missing up through the date of the well SS-25 incident.

27. YOU allege that SoCalGas knew that SS-25 released both crude oil and natural gas during the ALISO CANYON incident, but “did not disclose this fact to the Los Angeles County Department of Health.” (OPENING TESTIMONY, page 51).

a. Identify all actions taken by YOU to independently verify the claims alleged by the California Department of Public Health (“DPH”).

SED objects to this question on the grounds that it is unduly burdensome and overly broad, requiring SED to identify all actions it took to independently verify the claims alleged by DPH.

Notwithstanding these objections, SED requires more time to answer this question, and reserves the right to update its answer.

b. Confirm or deny that YOU considered SoCalGas’ March 21, 2019 response letter to the DPH when preparing YOUR OPENING TESTIMONY.

SED objects to this question to the extent it requests information that is protected by attorney-client and work product privileges. Without waiving these privileges, the answer is yes, as shown in SED's opening testimony on pages 51 and 52. Specifically, the passage in SED's testimony that shows SED considered SoCalGas's response letter to DPH states,

“SoCalGas responded to the Department of Public Health asserting ‘For all the above reasons, your suggestion that SoCalGas somehow withheld information or was otherwise not fully transparent with respect to the components of natural gas released during the incident, and your statements concerning DPH’s ability to perform a health assessment, are simply incorrect.’” SED's testimony references the March 21, 2019 letter in footnotes 383 and 384 of its opening testimony, which are cited in this passage.

c. Produce any and all COMMUNICATIONS by and between SED and the DPH, from October 23, 2015 through and including December 6, 2019.

SED objects to this question on the grounds that it requests information that is protected by the common interest privilege.

d. Produce any and all internal CPUC COMMUNICATIONS concerning DPH related to ALISO CANYON, from October 23, 2015 through and including December 6, 2019.

SED objects to this question on the grounds that it requests information that is protected by attorney client and work product privileges. SED also objects to this question on the grounds that it is unduly burdensome.

28. YOU allege that SoCalGas “did not have a well specific, well control plan that considered transient kill modeling or well deliverability. There was not quantitative understanding of well deliverability, although data were available, and well-established

industry practices existed for such analysis." (OPENING TESTIMONY, page 28).

a. Identify the "well-established industry standards" you reference on page 28 of YOUR OPENING TESTIMONY.

SED objects to this question as mischaracterizing its testimony, which uses the term "well-established industry practices"; not "well-established industry standards". SED understands the question to be asking about "well-established industry practices", and will answer the question with this understanding.

This statement is based upon excerpts quoted from the Blade Report, pages 5 and 238.

b. Identify and produce all DOCUMENTS, aside from the Blade Report, that include or reference the "well-established industry standards" you identify in response to Request 28(a).

SED further objects to this question as unduly burdensome in that it requests SED to gather all documents that include well-established industry standards.

Despite the undue burden of this question, SED requires more time to answer this question, and reserves the right to provide an additional substantive answer.

For reference to "simulations," a term used before "modeling" but essentially the same thing, refer to Donald L. Katz, AIME, U. of Michigan, "Monitoring Gas Storage Reservoirs," June 10, 1971, SPE PAPER No. 3287.

c. Identify the basis on which YOU contend that this allegation is a violation of Section 451.

SED objects to this question as mischaracterizing its opening testimony. The violations in this section are identified in this section on pages 38 and 39, and are quoted here.

> Given that SoCalGas had no well kill control plans and there are no data indicating transient modeling -- any modeling -- or analysis conducted to design the second through sixth well kill attempts, and such modeling would have provided the necessary information to successfully kill the well, SoCalGas violated Section 451.
>
> The Section 451 violation began November 13, 2015, the day SoCalGas unsuccessfully executed the second well kill attempt without modeling, and continued through February 11, 2016, the date of the successful relief well kill attempt. Because the second through sixth well kill attempts should have been successful with proper modeling, shareholders should be required to pay all expenses associated with each one. Also, because the relief well was started on December 4, 2015, after the second well kill attempt, the relief well would not have been needed had the second well kill attempt

been properly modeled. As such, shareholders should be required to pay all expenses associated with the relief well. SoCalGas's failure to provide well kill programs for relief well #2, well SS-25A and well SS-25B each constitute one violation of Section 451, for a total of three violations. Each of these violations span from November 13, 2015, the date
SoCalGas unsuccessfully executed the second well kill attempt, to February 11, 2016, the date of the successful relief well kill attempt.

Because surface plumbing failures prevented the well from being kept filled and the wellhead and surface casing were structurally unstable by kill attempt 6,276 such damage appears to have resulted from the prior unsuccessful kill attempt, thereby compromising the ability of kill attempt 7 to kill the well and end the safety consequences of the SS-25 leak. According to Blade, pumping for kill attempt 7 was terminated due to rocking of the wellhead and a subsequent failure of the injection connection. In other words, the ability to succeed on the seventh kill attempt was impaired by at least certain of the prior unsuccessful kill attempts, which should have been successful. This is a violation of Section 451.

The apparent conservative start date of this violation is November 25, 2015, the date that well kill attempt #6 was made. This violation continued until February 11, 2016, the date of the successful relief well kill attempt.

The basis for these violations is provided in the SED's opening testimony, Section II.B.5, pages 28 to 39.

29. YOU allege that the Division of Oil, Gas and Geothermal Resources ("DOGGR") responded to a 1994 SoCalGas proposal by stating, in part, "'Therefore, the monitoring program and static temperature surveys currently used by the Gas Company could be used to satisfy compliance of the requirements for mechanical integrity found in this section [California Code of Regulations Section 1724.10(k)(5)].'" (OPENING TESTIMONY, page 15). Do YOU disagree that DOGGR affirmatively stated that SoCalGas' activities complied with the cited regulation? If so, identify all grounds for your position.

SED's position is precisely that from SED testimony page 15, which SoCalGas quoted in the question. The grounds for the position is shown in the quote, and based upon the Blade Report at page 198, as cited in footnote 75.

30. Do YOU contend that YOU have authority to fine utilities for actions that are not within SED's regulatory purview, but instead are regulated exclusively by DOGGR?

SED objects to this question on the grounds that it calls for a legal conclusion as to SED's authority and SED's regulatory purview, as well as the exclusive regulatory purview of DOGGR. SED further objects to the question as argumentative, that it assumes facts not in evidence, that it mischaracterizes SED's testimony, that it is vague and ambiguous in that it fails to

provide context, vague as to time, and that it is overly broad.

31. Provide all contracts SED is aware of between underground gas storage operators, entered into during an emergency situation, that include a provision requiring the contractor to subject itself to the same provisions to cooperate with an investigation, by a regulator that has no jurisdiction over the contractor, as the principal.

SED objects to this question as vague in that it does not reference a page of SED's testimony; vague as to time; overly broad in asking for SED's awareness of all underground gas storage operators, including those not regulated by the Commission; and unduly burdensome.

Ex. I - 10

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Investigation	)	I.19-06-016
on the Commission's Own Motion	)	(Filed 6-27-19)
into the Operations and Practices	)	
of Southern California Gas Company	)	
with Respect to the Aliso Canyon	)	
Storage Facility and the release	)	
of natural gas, and Order to Show	)	
Cause Why Southern California Gas	)	
Company Should Not Be Sanctioned	)	
for Allowing the Uncontrolled	)	
Release of Natural Gas from Its	)	
Aliso Canyon Storage Facility.	)	
(U904G).	)	
_____	)	

DEPOSITION OF MARGARET C. FELTS
Los Angeles, California
Wednesday, February 5, 2020
MORNING SESSION

Reported by:
LINDA RYAN
CSR No. 9915
JOB No. 311652

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Investigation on the Commission's Own Motion into the Operations and Practices of Southern California Gas Company with Respect to the Aliso Canyon Storage Facility and the release of natural gas, and Order to Show Cause Why Southern California Gas Company Should Not Be Sanctioned for Allowing the Uncontrolled Release of Natural Gas from Its Aliso Canyon Storage Facility. (U904G).	)	I.19-06-016 (Filed 6-27-19)

Videotaped Deposition of MARGARET C. FELTS, pages 1 through 326, taken in accordance with Article 10 of the Commission's Rules of Practice and Procedure, taken on behalf of the Southern California Gas Company, at 300 South Grand Avenue, Twenty-Second Floor, Los Angeles, California, beginning at 9:23 a.m. and ending at 8:39 p.m. on Wednesday, February 5, 2020, before LINDA RYAN, Certified Shorthand Reporter No. 9915.

APPEARANCES:

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Also Present:
KAREN SHEA, SED
HEIDI FIELDING, Videographer

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Los Angeles, California
Wednesday, February 5, 2020
9:23 a.m. - 12:15 p.m.

PLEASE BE ADVISED THAT THE DISMANTLING AND/OR UNBINDING OF THE ORIGINAL TRANSCRIPT WILL VOID THE CERTIFICATION OF THE CERTIFIED SHORTHAND REPORTER AND NULLIFY THE INTEGRITY OF THE ORIGINAL TRANSCRIPT.

THE VIDEOGRAPHER: Good morning.

Here begins media number one in the deposition of Margaret C. Felts, Volume 1, in the matter of Aliso Canyon Storage Facility. This case is before the Public Utilities Commission of the State of California, the case number is 1.19-06-016.

Today's date is February the 5th of the year 2020 and the time on the video monitor is 9:23 a.m.

This deposition is taking place at 300 South Grand Avenue, 22nd floor, in Los Angeles, California 90071-3132, and is being taken on behalf of the Defendants.

The videographer is Heidi Fielding, appearing on behalf of Biehl, et al., Certified Shorthand Reporters.

The certified stenographic reporter preparing the official transcript of today's deposition is Linda Ryan, appearing on behalf of Biehl, et al., Certified Shorthand Reporters.

Neither the reporter nor myself are employees of Biehl, et al., Certified Shorthand Reporters.

Counsel, would you please identify yourselves and state whom you represent.

MR. STODDARD: Jack Stoddard for Southern California Gas.

MR. MOSHFEGH: Pejman Moshfegh also for Southern California Gas.

MS. PATEL: Avisha Patel on behalf of Southern California Gas.

MS. MORTAZAVI: Setareh Mortazavi on behalf of Southern California Gas Company.

MR. GRUEN: Darryl Gruen on behalf of the Safety Enforcement Division of the California Public Utilities Commission.

THE VIDEOGRAPHER: And if our court reporter would please administer the oath to the witness.

(Witness sworn.)

THE WITNESS: I do.

THE VIDEOGRAPHER: Please begin.

MR. STODDARD: Thank you.

MARGARET C. FELTS,
having been first duly sworn
and administered an oath
pursuant to California CCP 2094,
was examined and testified as follows:

EXAMINATION

BY MR. STODDARD

Q Would you please state your name and your home address.

A Margaret C. Felts. And I live at 633 Dodge Street, Delta, Colorado 81416.

Q Thank you, Ms. Felts.

And is this the first time you've ever been deposed?

A No.

Q How many times have you been deposed before?

MR. STODDARD: One moment, brief break.

THE VIDEOGRAPHER: Do you wish to go off the record, Counsel?

(Whereupon Ms. Shea entered the deposition proceedings.)

MR. STODDARD: Yes, please.

THE VIDEOGRAPHER: Just a moment.

We are off the record at 9:26 a.m.

(Off the record.)

THE VIDEOGRAPHER: We are back on the record at 9:26 a.m.

MR. STODDARD: Ms. Felts, apologies.

Before we get into the questioning, we're going to address a few initial housekeeping items for purposes of the record.

The first is that we had had prior discussions regarding reimbursement or compensation for Ms. Felts' appearance today.

SoCalGas agrees to pay for -- pay Ms. Felts directly for her time in appearing in today's deposition and -- with the understanding that SED will pay for her travel time as well as travel expenses.

MR. GRUEN: Thank you.

And just for the record, SED notes SED does not stipulate to paying for Ms. Felts' travel expenses or other expenses related to the deposition today, and SED reserves the right to request an ALJ ruling requiring Southern California Gas to pay for those expenses; so that's for the record.

A couple of other items.

SED will be requesting copies of the videotape of today's deposition of Ms. Felts as well as the transcripts of the deposition.

And just for the record, we'll note objections as we see appropriate if we -- if we think they're appropriate.

But for the record, we -- I'm in receipt of, for Ms. Felts, a copy of her testimony in Southern California Gas Company's and San Diego Gas & Electric Company's Application 1509013, which is her testimony for UCAN, a party that counsel is not present today.

And our understanding is that any questions related to that testimony is for the sole and exclusive purpose of the noticed deposition on the Aliso Canyon Order Instituting Investigation and Order to Show Cause, and that anything that Ms. Felts says today should not -- it's not appropriate to use anything she says related to that testimony in a 1509013 in that proceeding; so we'll note objections accordingly, but we wanted to make that clear for the record at the outset.

MR. STODDARD: Noted.

And SoCalGas's response on that is that SoCalGas doesn't waive any right to ask a question about any document or issue within Ms. Felts' scope

of knowledge or area of expertise or prior testimony or any other document; however, we note your objection regarding the use of that transcript for purposes of the PSRP proceeding.

MR. GRUEN: Your point is noted as well.

Thank you.

BY MR. STODDARD:

Q Okay. Ms. Felts, thank you. I believe we had just gotten through your name and home address.

And I had asked whether you had been deposed before and you indicated that you had been. And then I had asked how many approximate depositions had you submitted to, and I don't believe I had an answer to that question. But if I did, I apologize.

A And I don't have a number, but it's less than ten.

Q Less than ten. Okay.

And do you have an approximate number of those where you would have been an expert witness for purposes of the deposition?

A All of them.

Q Okay. So this isn't new to you, so I'm going to, you know, recount a few kind of rules of the road for the deposition. They will all be familiar to you I'm sure.

But first and most importantly, please speak clearly and slowly, and I will try to do so as well. Please respond verbally to any questions.

The court reporter can't capture nods or gestures; so make sure that you answer with words, "yes," "no," or otherwise.

The court reporter can't capture what we're saying if we're interrupting each other and talking over each other; so please don't interrupt me, and I will try not to interrupt you.

Wait until the question is asked before you answer it, and I will wait until you finish your answer if I can before I ask my next question.

Also, in general, your attorney may state objections for the record. But you should still answer the question unless you're specifically directed by your attorney not to answer the question.

And finally, in terms of breaks, we're going to plan on taking a break, you know, probably approximately at least every hour, but if you need a break at any time, just say so. But please answer any question that was asked prior to taking a break.

A Okay.

Q And Ms. Felts, are you represented here by counsel today?

A Yes.
Q And who is your counsel?
A Darryl Gruen.
Q Thank you.
And is Mr. Gruen representing you in your personal capacity?
MR. GRUEN: I'm sorry, just to -- maybe to clarify for the record.
Is the question whether --
Just to clarify maybe you could ask is -- whether she is being represented as a witness for SED or personally.
BY MR. STODDARD:
Q Ms. Felts, today here you are appearing as a witness for SED; is that correct?
A Yes.
Q And so Mr. Gruen is representing SED and you as a witness for SED, correct?
A Yes.
MR. STODDARD: Thank you.
I'd like to mark Exhibit 1-1.
(Deposition Exhibit 1-1 was marked for identification and is attached hereto.)
BY MR. STODDARD:

Q Ms. Felts, do you recognize this document?
A Yes.
Q This is a deposition notice asking for your appearance here today; is that correct?
A Yes.
Q If you can turn to page 3 of the document.
Do you see where it asks for documents to be produced?
A Yes.
Q And the first request is for "All work papers not previously produced to SoCalGas that Margaret Felts generated or relied upon in connection with the above captioned matter."
A Yes.
Q Do you see that?
Did you collect documents in response to that request?
A Everything was already provided to you.
Q Okay. So would it be accurate to say that we have -- that all work papers that would be responsive to this request have been collected and provided to SoCalGas prior to today's deposition?
MR. GRUEN: Let me just note an objection for the record, and I think we had agreed to this, that the definition of "work papers" excludes anything

that would be used for future testimony, such as the reply or the rebuttal testimony. And we understand the definition to be qualified in such a way that it's only applying to the testimony that Ms. Felts has produced in this proceeding thus far.

MR. STODDARD: Objection noted.

I'm going to restate the question and ask that Ms. Felts answer it.

Q I'll break it into two different questions though.

First, all work papers that were generated prior to service of your opening testimony or SED's opening testimony in this proceeding, were those collected and produced to SoCalGas prior to today's deposition?

A Yes.

Q Okay. And have you generated additional work papers since then, since service of your opening testimony that were not produced for purposes of today's deposition?

MR. GRUEN: Again, I'm just going to object on the grounds that those questions -- questions related to work papers since the production of testimony are protected on the grounds of attorney-client or -- and/or work product privilege; so I'm going to

instruct the witness not to answer the question, the second question.

BY MR. STODDARD:

Q Okay. Ms. Felts, question number 2 requests all written testimony or reports that you prepared related to underground storage facilities, correct?

A Yes.

Q And did you collect and produce any written testimony or reports as requested by that item?

A I looked for testimony in the Montebello Storage Unit case, but I don't have that file anymore; so I don't have it. I think I produced testimony at the time. I don't have a copy of it.

I also have some documents related to the Playa del Rey case that I worked on. I don't believe a final testimony was ever published in that case. I think it was settled.

MR. STODDARD: Thank you very much.

All right. I would like to mark Exhibit 1-2.

(Deposition Exhibit 1-2 was marked for identification and is attached hereto.)

BY MR. STODDARD:

Q Ms. Felts, do you recognize this document?

A Yes.
Q And this is your resume, correct?
A Yes.
Q This is the resume that you produced to SoCalGas and which you included with your -- with their testimony; is that correct?
A Yes.
Q I'd like to ask you a few questions about this.
First -- the first sentence of this document states that you serve as lead technical consultant to law firms, regulatory agencies and private entities on environmental, energy and corporate fraud cases concentrating on behind-the-scene discovery, research and strategy development.
Do you see that?
A Yes.
Q Are there any current matters aside from the one that we're here for today that you're working on?
A Yes.
Q Are you able to tell us about those matters?
MR. GRUEN: Just note an objection to the extent that they're unrelated and irrelevant to the proceeding at hand, Aliso -- to the Aliso Order Instituting Investigation and Order to Show Cause.

But she can go ahead and answer.

MR. STODDARD: Yeah.

We don't know whether they're relevant or not unless we know what they are.

MR. GRUEN: Understood.

THE WITNESS: There are two cases that are open:

One has to do with a leaking gasoline pipeline owned by an oil company in the east, in Pennsylvania, it's a private matter; so that's about as much as I can tell you.

BY MR. STODDARD:

Q You said a gasoline pipeline?

A Yes.

Q Like automotive fuel?

A Yes.

Q Okay. And you said that's in the east; is that correct?

A It's in Pennsylvania.

Q And that's a private matter between two corporate entities?

A It's between a land owner and the oil company.

Q And which party are you working for in that case?

A The private --

The plaintiff.

Q Okay. And are you a consulting expert in that case or testifying expert?

A Both.

Q "Both." Okay.

And you said there was another case?

A A small property issue in Northern California having to do with, again, a private land owner and PG&E. I'm representing --

I'm the expert for the plaintiff, the land owner.

Q Okay. And does that relate to PG&E electrical facilities?

A No, it's PG&E gas.

Q It's related to PG&E Gas. Okay.

Does it involve a gas storage facility?

A No. Pipeline.

Q Okay. Ms. Felts, I'm going to direct you down to the next section where it says "Specialties." And it says "Discovery and technical strategies for complexion cases involving," and then it lists a variety of subject matter areas.

Do you see that?

A Yes.

Q What sorts of discovery and technical

strategies do you specialize in?

A I write discovery questions, and I help with developing a strategy based on data that has been collected or been provided. I also do research to supplement that with additional information.

Q What sort of research?

A Technical research or flush out the issues of a case, help attorneys understand technical issues.

Q Thank you.

Under the next bullet which states "Gas and Electric Utilities regulatory cases," it states "Records Management Assessment" under the first sub bullet there.

Do you see that?

A Yes.

Q What exactly is "Records Management Assessment"?

A To do a records review to see if the recordkeeping practices are in keeping with standard or what would be expected in the industry that the case is working in.

Q Thank you.

The next bullet down -- or two, I'm sorry, skip it, says "Fraud" and then "Incident Assessment."

A Yes.
Q What do you mean by "Incident Assessment"?
A So if there was a spill, say I would do an assessment of the records and the data that resulted from that or transcripts or whatever is -- whatever records are available, and assess the situation from the beginning to the end and probably develop a report to whoever I was working for, usually an attorney.
Q Okay. So in the context of incident assessments it would be fair to say that your review or investigation is based on examination and collection and review of records and documents?
A Yes.
Q And that you would prepare a report or testimony in those cases?
A Usually at that level an incident assessment in my mind would occur very early on. When somebody contacts me, I look at what they have.
Maybe look at news media or reports or whatever I can -- information is available and then do a short report or -- like an interim report to the attorney that gives them an idea of what I think -- what I think the incident information provides and what -- where the case might go on a technical level,

not on a legal level.

Q All right. Underneath that bullet you see where it says "Pipeline Integrity Assessment"?

A Yes.

Q Can you explain, please, what do you mean by that in this context?

A Well, again, so we're looking at records that have to do with a pipeline and whether or not the condition of the pipeline was sound or if there was an issue with the pipeline that can be identified early on as part of the case.

Q Based on the records?

A Yes.

Q Okay. And for "Underground Gas Storage Assessment"?

A Similar. Similar to the pipeline assessment, you just --

It's based on record reviews.

Q And what are you assessing relative to underground gas storage in that case?

A Well, it would depend on what the issue is because they seem to vary quite a bit. But it would be usually some sort of a gas leak from the storage unit. Sometimes a combined environmental issue that, you know, evolves from a complaint from a neighbor or

neighborhood or somebody that lives near an underground storage area.

Q Okay. Does it include assessment of gas storage wells?

A Yes.

Q Okay. And in all of these instances, you have four different, or I guess five different items here are described as assessments, "Records Management Assessment, Incident Assessment, Tree and Pole Program Assessment, Pipeline Integrity Assessment," and "Underground Storage Assessment."

For each of these, these are based upon your review of records?

A Yes.

Q So not direct examination of physical evidence?

A In the tree and pole program assessment, I actually went out and did physical inspections in some instances.

Q Okay. On any of these assessments, do you interview people or witnesses?

A Not without an attorney present with me.

Q Okay. The next bullet down below that bullet is "Oil & Gas Industry Cases."

Are these generally similar to what we've

covered in underground gas storage assessment and pipeline assessment, or is this a different category of cases in your view?

A This is a category that I have not worked in for quite some time; I would say for at least 15 years. Where previously I was doing work in oil price projections, oil price setting or oil and refinery product price setting. There was -- there were quite a few different types of issues that were coming up that I was hired to review or help on. I haven't done that for a long time.

Q By "price setting," do you mean price fixing?

A Yes.

Q Okay. And this related to --

Were these regulated oil and gas companies? Or I guess let me restate that. I'm sorry.

Does this involve public utilities?

A No.

Q The next bullet down is "Natural Gas Supply and Demand Assessment."

Do you see that?

A Yes.

Q Can you describe what this work entailed?

A Again, this is an area that I haven't really

worked that much in recently, but in the 1980s and '90s, I worked quite a bit on that, and it had to do with assessing the available supply of natural gas and forecasting the supply and demand curves.

Q And was this related to supply of natural gas regionally?

A It was supply of natural gas within the United States, and it would have included Mexico.

Q Okay. So this was kind of a broad market analysis?

A Yes, because your pipeline is connected. I mean, the supplies cross borders; so it can't be just California. It would have to be nationally and in some instances international.

Q Because the natural gas pipeline system is integrated?

A Yes.

Q Kind of almost at the continental level?

A Yes.

Q And so a significant natural gas resource or piece of infrastructure is impacted by even relatively far flung demand across the country; is that correct?

A Well, I don't know if you have far flung demand. And the demand curves turn out to be fairly

consistent from one year to the next.

But there was a period of time when there were some entities who believed that either natural gas demand was going to go way up or way down, and so there would be a call for some sort of a forecast. And this is early -- probably before the year, I want to say 2000, because sometime around 2000, 2004 the Energy Information Administration stepped in and started providing some pretty good sound information, data, and forecasts that people could access easily. And it was easier for me to give people a link to that than to try to generate my own forecasts; so that demand for that work diminished.

Q The next bullet down is "Groundwater Contamination."

Can you please explain the work that you've done in that area?

A In the 1990s -- approximately 1990 to about 2000, I had an environmental company with employees, and we did environmental assessments and investigations, mostly having to do with groundwater.

And then year -- some time around 1998 to about 2002 I did a research project for Lloyds of London. And the basic question was who knew what, when about groundwater contamination in California

primarily, but it ended up extending throughout the United States.

And that review, I researched records back to I think it was 1895 and forward and developed a huge database about groundwater contamination.

Q So was the work that you were doing on groundwater contamination records-based work or was it field work?

A It was --

So the work that I did as a consultant was field work. We actually drilled and constructed groundwater monitoring systems. The research for Lloyds of London was records-based.

Q Okay. And was the groundwater contamination work you did particular to energy?

A No.

Q Okay. The next item you have on the list is "Hazardous waste disposal and site cleanup," with sub bullets for "CERCLA, RCRA" and "Underground Storage Tanks."

Do you see that?

A Yes.

Q What types of underground storage tanks did this concern?

A Gasoline, diesel, and anything else that was

in a tank below the ground.

Q Okay. This does not relate to natural gas storage fields, however --

A No.

Q -- correct? Okay.

All right. Moving over to your employment history. The first item that you identify is "Litigation Consultant 1983 - Present."

Do you see that?

A Yes.

Q I would note that that period of time overlaps with a number of other positions listed on your employment history.

A Yes.

Q Did you work both as a litigation consultant at the same time that you were employed by others?

A Yes. During that period of time there was only a -- there was a period of about five years when I worked for the California Communications Association when I was not working any active litigation cases. I had a couple that were sort of in remission that came alive later, but I wasn't working on them during that five years.

Q Was there any particular reason why you didn't take on cases during that period of time?

A Well, no particular reason. I think I was just busy doing work with the telephone companies and the association.

Q Okay. The next item down the list --

So we just discussed the California Communications Association.

From 1995 to 1997 you were a senior consultant for Dames & Moore; is that correct?

A Yes.

Q And what was your role there?

A I was just an engineer. I ran an engineering group in Northern California. We worked cases -- I worked cases in Washington state and Northern California. My team worked other cases in mostly Northern California, some in San Francisco, Bay area cases.

Q What sorts of engineering?

A Well, some were -- some of it was environmental engineering. There was air emission cases. There was groundwater cases.

Q Okay.

A There were permits that were being applied for having to do with complicated construction.

Q Okay. The next item down says --

MR. GRUEN: I'm sorry, I just want to clarify.

Are you finished answering that question?
THE WITNESS: Yes.
MR. GRUEN: Okay.
BY MR. STODDARD:
Q The next item down shows that from 1993 to 1995 you were the Deputy Director at the California Department of Toxic Substances Control; is that correct?
A Yes.
Q Can you describe your work there during that time period?
A I was in charge of the statewide site mitigation program; so we handled oversight of Superfund sites, state equivalent of Superfund sites. So those would be all funded and handled with -- by my team.
And then we had oversight over all of the hazardous waste site mitigation or cleanup, investigation and cleanups by private parties that were over -- you know, overseen by the state. And then I had an emergency management -- or emergency response group that handled response to emergencies that involved hazardous waste.
For instance, if a storm came in and washed a bunch of propane tanks down a river, we would go

out and deal with the problem. It was on-site work. And we also handled all of the drug lab cleanups.

Let me think.

We had a geologic group that did geologic assessments for site -- contaminated sites.

Q Did any of that work, as you recall, relate to natural gas facilities or natural gas?

A So if there was a complaint that came in for exposure to natural gas, we would have a team respond to it.

But typically anything having to do with a natural gas storage would be deferred to the lead agency, which would probably be the Public Utilities Commission or the Division of Oil and Gas. But we might join a team for an assessment on a site.

Q Do you recall any specific such cases?

A No, not offhand.

Q Your tenure there was fairly short, for two years.

Was there any particular reason that you left after two years?

A It was a political appointment.

Q Similarly your tenure at Dames & Moore was from 1995 to 1997.

Was there any particular reason that you

left that position after two years?

A They offered me a job, and I was in transition back from a political appointment to a consulting firm, and they agreed that I could sort of ride on their coattails while I made that transition; so I went to Dames & Moore. I pulled my old clients and worked to shift back out.

Q Okay. Jumping down to Division Chief of Engineering under the Department of Defense McClellan Air Force Base, 1985 to 1990.

Do you see that?

A Yes.

Q Can you please tell us a little bit about that work?

A Okay. So McClellan Air Force Base had a very bad contamination problem. It's an Air Force/Army flight depot, and for years they had been discarding all of their chemical waste into big pits on the west side of the base.

So they were challenged with trying to do something about cleaning up that when it started contaminating groundwater wells west of the base. And they hired me to come on initially to consult with them about what to do about the groundwater contamination.

They immediately offered an employment position, which turned in to a job of not only dealing with the immediate problem but of developing a model environmental program for the Department of Defense; so I helped them set that up. And I started in the Superfund side.

I got that going, and I moved over to the RCRA program and implemented that. Then I was in charge of the air emissions program in addition to RCRA; so basically I was writing and developing programs to put that in place. And then that was -- that program was proliferated to the rest of the depots and later to the rest to the Department of Defense facilities.

Q Okay. And did that job have any involvement with natural gas infrastructure facilities?

A No.

Q The next item down is "Environmental Contractor Invictus Corp." There is no time period for this.

Do you have a time period?

A That was my own company. 1982 to '85.

Q And this is the -- is this the same company that you were referring to when we were discussing groundwater contamination work under "Specialties"

before?

A Yes. And it had another name. It was -- seems like it started out as Clemen Environmental Services and may have continued to exist during the time I was at the Department of Defense.

Q The company continued to exist?

A Yes.

Q So this is a company you started and then left when you joined the Department of Defense?

A Well, I mean it was my own company.

So if you look at this, it started in 1993 as Clemen Environmental Services, and then I continued to carry contracts, consulting contracts, including with the PUC while I was at McClellan at the Department of Defense.

Q I'm sorry, can you slow down for one moment. I think you said you see where it references Clemen in 1993. And I don't see --

Forgive me if I'm missing it, but I don't see where you're pointing to on the document.

A I'm sorry, Deputy Director 1993 to 1995.

Q Yes.

A Okay. So Division Chief of Engineering is 1985 to 1990 so there is a three-year period in there. That was also an active environmental period

which would have been under Invictus Corporation.

Q Okay. So --

A So I'm saying, okay, let's --

The starting date for Clemen Environmental Services, which is Invictus Corporation, because that was before it was incorporated, is 1983. And so if you put 1983 to 1993, that would be the period of time that the dates that would go behind Invictus Corporation.

Does that make sense?

Q So just to confirm, the dates that should go immediately to the right of the environmental contract line should be 1983 to 1993?

A I think that's the best.

Q Okay. And the Invictus Corp work continued for a period of three years while you were also Division Chief of Engineering for the Department of Defense?

A Yes.

Q Okay. And you indicated that you had contracts with the PUC?

A Yes.

Q That was with Invictus?

A The contract itself was either with Clemen Environmental Services or Invictus. I actually don't

remember the date of the incorporation for that and the name change. But it's all the same thing. It was a private company that was then incorporated in the State of California and then the name --

Q How do you spell Clemen?

A C-L-E-M-E-N.

Q So Clemen is not identified on here. Invictus Corp is.

But Invictus Corp and Clemen are one and the same?

A Yes.

Q How many appointments did you have with the California Public Utilities Commission approximately?

A Well, let's first finish the dates on that one.

So you had to 1993, and then I picked it up again in 1997 to about 2004; so add those dates to the line outside of environmental contractor. And the number of PUC cases, I've never counted those.

Q Approximate, would you say it was, you know, more than 20 contracts?

A I'd say it's right around 20.

Q Okay. And all of these contracts related to groundwater contamination matters?

A No. They -- they were across the board; so

there was a gas plant case, a coal-fired power plant, Helms power plant, which is water storage.

There were three fraud cases involving utilities. There was tree trimming case and pole maintenance. There were two underground storage cases, which was Montebello and Playa del Rey.

Q So I apologize, I don't mean to interrupt, Ms. Felts.

But just to summarize, because I think we will get into some of this in a moment. But to clarify, because I hadn't appreciated this before, the contracts between Invictus and PUC were for expert services?

A Yes.

Q So it wasn't related to engineering work specifically, engineering services related to the groundwater contamination?

A No.

Q Okay. But Invictus also did that work?

A Yes.

Q Not for the PUC?

A Yes.

Q Okay. Was any of --

Do you recall any of the contracts with the PUC for Invictus being for work other than expert

consulting or testifying services?

A No.

Q Okay. Thank you.

Next item down briefly, do you recall the tenure and the dates for "Energy Specialist" at the "California Energy Commission"?

A I think I was there from 1980 to 1983, I think. Late '80 to '83, early '83.

Q And what was your role as an energy specialist?

A I was in charge of the group -- I don't remember the name of the group. It was in -- it was the fuels office, and I was in charge of natural gas and refining forecasts.

Q This was forecasting work related to supply and demand?

A Yes.

Q So this did not relate to energy infrastructure integrity?

A No.

Q Or to particular incidents?

A No.

Q Okay. Next item down it identifies you as a process engineer for Celanese -- apologies if I mispronounce this, Celanese Plastics and Specialties?

A Yes.
Q What did you do as a process engineer?
A I was one of two engineers at a plant in West Texas, Vernon, Texas that manufactured guar powder, which was produced in mass specially for the oil industry for fracking.
Q What was your specific role with respect to the production of guar?
A Well, it was an interesting process plant where we -- I had to grind a bean basically -- guar is an agricultural product, and we had to grind it into a dry powder; so in the meantime in order to get the properties that were required of that powder as an end product, it had to go through a reactive process where there was a chemical reaction to give it those properties.
So I was in charge of the process from front to end to get that to happen and just day-to-day engineering problems at the plant. And also handled environmental problems related to their waste treatment and air emissions.
Q And how many years were you in that position?
A About two.
Q And finally it appears that you were a

process engineer for Amoco Oil Company in Yorktown. Is that Yorktown, Pennsylvania?

A Virginia.

Q "Virginia"?

What did you do as a process engineer for Amoco?

A Again, worked a variety of refining engineering projects; so I was trained to run their linear program on the major -- on the mainframe, which was linked to I think Whiting.

Anyway, they had five refineries so the mainframe linear program was set up so that all of the oil movements that went from one refinery to the other and the production of the products was coordinated.

And so I was in charge and spent a lot of my time managing the inputs and outputs of the refinery and making sure that those specs of the products met the requirements for the outgoing demand; so we had a large product slate. It was a full-fledged refinery, and everything had to balance. And then also dealt with the blending of crude oils, because at that refinery we were using both domestic crude and foreign crude. And so it was an interesting project.

Q And how long were you in that position?

A About three years.
Q Okay. And was that your first job out of graduate school?
A Out of engineering school.
Q Out of engineering school.
What year do you recall you would have started that? Would it be '70 -- mid-'70s?
A 1977.
Q Okay. And then below that we see "Education," and it appears that you are an attorney, and you got your law degree from the Pacific McGeorge School of Law; is that correct?
A Yes.
Q And you got your MS in energy environmental engineering from LaSalle?
A Yes.
Q Are there any other degrees that aren't listed on here?
A No. I have a certification in linear programming.
Q Certification, any other certifications we should be aware of?
A No.
Q Any other certifications at all?
A I have a general engineering license that is

not on there. It's currently on hold with the State of California.

Q What does that mean?

A It means I pay less because I'm not using it; so it still could be activated in a day if I went down and paid them the extra money.

Q Do you have an engineering license that is active in another jurisdiction?

A No.

Q Okay. Are you --

It identifies you as having a Washington State Bar number.

Is that active or is that inactive?

A Active.

Q Active.

And you're a member of the Phi Delta Phi International Legal Fraternity. Is that a membership or an honor?

A It was an invitation. I have a lifetime membership in it. It's --

Q Impressive.

All right. Turning to the next page, and we'll touch on a few of these but not all.

First question is the first case here identified "2018 - 2019 Oil Company Pipeline Leak,

Client: Private Law Firm."
A Yes.
Q Is this matter concluded in 2019?
A No. It's still open.
Q It's ongoing. Okay.
And is this the same matter -- no, this is an oil pipeline not gasoline.
A It's the same matter.
Q It's the same matter?
A Yes.
Q So this is a gasoline company pipeline leak?
A It's an oil company that owns a gasoline pipeline. They own other pipelines too.
Q All right. And are you able to tell us who the private law firm is?
A No.
Q Okay. Below that, "2016 - 2018 PG&E General Rate Case FERC Docket." I won't read the docket number there.
Do you see that there?
A Yes.
Q And your client on this is the California Public Utilities Commission?
A Yes.
Q Is this related to --

Is this a PG&E electric grate case?
A No. It's the San Bruno case.
Q This is the San Bruno case.
And this case concluded?
A Yes.
Q And what was your work in this case?
A I was the expert witness on a records case -- records-related case.
Q And you submitted testimony before FERC?
A No.
Oh, wait. Are we looking at the same --
Q The first item under 2016 to 2018, second item on the page. It shows "FERC Docket No. ER 16-2320-000."
A This looks like an error in my --
Q Is that a mistake?
A I think that's an error. I don't remember a FERC docket on San Bruno.
Q Could you please correct your resume and send us a corrected one at your convenience?
A Okay. Just a minute.
Q The next item down is "SDG&E CPCN For Pipeline Reliability and safety project."
Do you see that?
A Yes.

Q And this identifies your client as UCAN?
A Yes.
Q And you are UCAN's expert witness; is that correct?
A Yes.
Q And this is an ongoing matter?
A Yes. I am -- can I correct --
I am no longer on that case because UCAN, I don't believe, continued in the case. I don't think they're an active participant in it right now; so they paid me my final payment at the end of the first phase.
Q Which was when?
A It would have been in -- I think it actually ended in the end of 2017, if I recall, and I received my final payment in 2018.
Q Okay. And you prepared testimony that was served in that case, correct?
A Yes.
Q All right. The next item down says "2014 - 2016," and the first item is United States versus Pacific Gas & Electric Company, and it indicates it was related to the San Bruno pipeline explosion criminal case; is that correct?
A Yes.

Q And that your client there was the United States Department of Justice; is that correct?
A Yes.
Q Were you --
What was your role in that case?
A I was a consulting expert, and I helped review records and developed discovery.
Q Okay. On any particular scope of issues?
A It was San Bruno. It was just having to do with recordkeeping and technical issues having to do with the pipeline explosion.
Q Okay. What sort of technical issues beyond recordkeeping?
A I reviewed some of the documents having to do with the original installation and maintenance of the pipeline and maybe some inspection records.
Q Thank you.
The next item down identifies an application ATCO Pipelines, "Urban Pipeline Replacement Project, Client: ATCO."
A Uh-huh, yes.
Q Who is ATCO?
A It's a gas utility in Canada. And their offices are in Calgary, I believe.
Q And who was this proceeding before?

A It would have been the equivalent of the Public Utilities Commission only in Alberta.

Q Okay. And this matter is now concluded?

A Well, my contract is concluded on that. I don't know if the case actually closed yet.

Q Okay. And what was your role in that case?

A Okay. Let's see, the pipeline company wanted to get approval to put in a new pipeline that would be installed in a utility corridor around the city and take out of service existing gas lines in the city that were in -- buried in streets that were lined with housing now. And then they wanted -- they were not going to abandon that service.

They were going to de-rate the lines that were providing service within the city to the low pressure service. And so they were asking for my help in convincing the public sector there that it would be a good idea to move the high pressure gas service to a corridor rather than having it run under their homes.

Q And so you were a testifying expert in that case?

A Yes, for The Gas Company.

Q And you served testimony?

A Yes.

Q Okay. Next item down 2011 to present OII, 1.11-02-016 related to the San Bruno explosion. This appears that your role is ongoing.

What is the ongoing work that you're doing?

A No, it's not ongoing. Old. This is done.

Q When did it --

When was it completed?

A 200- -- 2018.

Q Okay. Can you please add that to the list of corrections to your resume?

Jumping down to the bottom of this column, where it says "Playa del Rey Gas Storage Integrity SoCal Edison" --

A Yeah, that's an error. I knew about that.

Q So that should say SoCalGas?

A Yes. I'll correct that.

Q And the description is "Research and evaluation of data related to the operations, maintenance integrity of the Playa del Rey gas storage facility and the proposed sale of surface property."

And your client was the California Public Utilities Commission Division of Ratepayer Advocates; is that correct?

A Yes.

Q Can you please describe a little bit the scope of your work in this matter?

A It was, again, a records review, and there was --

It was probably a reasonableness case where the Gas Company was asking for some money to cover some costs, and as I recall, there may have been a -- yes; so there was a proposed sale of surface property, and they wanted to -- the PUC wanted an assessment of what the sale of the property would involve as far as technical issues related to gas storage.

And there was also an environmental component of this having to do with contamination in Ballona Creek, I think; so I did an interim or a -- you know, an initial assessment for the Public Utilities Commission, and that's the case that I said I think must have settled because I don't recall a final testimony in that case.

Q So as you recall, the case settled prior to testimony?

A I --

Yes, I'm sure I didn't testify in that case.

Q Okay. And do you recall what the specific integrity issues were that you researched and

evaluated?

A There was --

There were some complaints of leakage of natural gas from wells.

Q Okay. So you reviewed those complaints and related records?

A Records, historical records having to do with the storage unit; so there was a few rounds of discovery. I had quite a few gas documents to review from the utility.

And then I did independent research on the groundwater contamination or groundwater issues. Seems like there was a -- somebody who complained or thought that the gas was coming from a storage unit up through the creek.

It was a private resident who was out there counting bubbles in the creek and then filed a complaint. And so I did some research into prior contamination in the creek that could have been causing that.

Q Did you determine whether or not it was being caused by prior contamination in the creek?

A My -- I think --

As I recall my assessment was that it wasn't coming from the gas storage unit.

Q Okay. And in terms of the reference to integrity here, did it -- it didn't relate specifically to SoCalGas well integrity monitoring practices?

A No, not -- excuse me, not integrity monitoring that I can recall.

There was a problem with one or more wells leaking, and I recall one of the wells actually was vented up through a house, which was crazy. Without being able to look back at data, which I don't have anymore, I can't really tell you much more. I'm just telling you what I remember.

Q What you recall. Okay, thank you.

All right. Jumping to the next column, do you see where it states "Application of SoCalGas Company to sell its storage field in Montebello, California, pursuant to Public Utilities Code Section 851"?

A Yes.

Q And then it says "Evaluation of technical data related to the integrity of the Montebello gas storage field."

And your client again there was the Division of Ratepayer Advocates?

A Yes.

Q Were you a testifying expert in this case?
A I filed testimony.
Q You served testimony that you were not able to locate?
A Yes.
Q For purposes of producing it for today's deposition; is that correct?
A Yes.
Q Do you recall whether it was multiple rounds of testimony?
A I expect there was a rebuttal.
Q Okay.
A But I don't remember actually testifying in that case, and I don't -- testifying at the hearings. I don't know if there were hearings and the case --
My part, my evaluation of it was evaluation of storage unit data and leakage; so the gas storage facility was leaking.
Q Okay. Do you recall whether these were operational or abandoned wells?
A What I recall about my part of -- my study of it was not that it was leaking through wells, which it may have been, but that the storage unit itself was leaking. In other words, the geology wasn't containing the gas.

Q So integrity here refers to reservoir integrity, not well integrity?
A That's correct.
Q Okay. Thank you.
You identify a number of other cases on your resume.
Are there any others that relate to gas storage that you see here?
A No.
Q Okay. Ms. Felts, you don't identify any publications on here.
Do you have any publications or articles?
A I have a list somewhere. They're really old. I haven't published anything other than testimonies for a long time.
Q Do any of those publications as far as you recall relate to gas storage?
A No.
Q Okay. Ms. Felts, you've been a testifying expert in a number of disputes including regulatory and civil proceedings, correct?
A Yes.
Q And the civil proceedings include both arbitrations and testimony in court?
A Yes.

Q Have your qualifications as an expert ever been rejected?

A No.

Q Ms. Felts, we identified a number of inaccuracies in this resume.

MR. GRUEN: Objection. To the characterization of "a number of inaccuracies" --

But she can answer.

BY MR. STODDARD:

Q Okay. Ms. Felts, we identified inaccuracies related to items on page 2 of your resume, related to the PG&E FERC docket under 2016 and 2018, identification of the utility in connection with the Playa del Rey storage integrity item, as well as on the first page an incomplete account of the tenure for Invictus Corp.

Based on our discussion there should also be time periods between Dames & Moore and the California Communications Association and potentially between the Department of Defense, McClellan Air Force base and the Department of Toxic Substances Control.

Do you agree?

A Do you want me to add dates to make this more consistent on the front page with the time schedule? In other words, you want me to insert

environmental into the periods?

Q Well, what I would like is a complete accounting of your employment history, and based on our questioning a few moments ago, it sounded like there were interim periods of time where your own company, Invictus Corp or Clemen Energy Services, there were tenures -- there are periods of time for work you did with Invictus that should be listed here between other positions.

A Okay. So when I wrote this, I tried to make it easier by putting litigation consultant 1983 to present to cover that because all of those interim periods I was doing litigation work.

So, I mean, I can rewrite it so that it covers all date periods.

Q If you could clarify and confirm that that's accurate, we would appreciate it. And then make the corrections that we discussed on page 2, and then please confirm whether this is otherwise complete and accurate.

As you sit here today, to your knowledge, is this otherwise a complete and accurate record of your employment history and testifying experience and education?

A Yes. I looked at it, and I don't think

there are any more -- any other errors.

The one I spotted was the Playa del Rey.

I didn't notice that I needed to fix the date on the OII.

And the FERC case, I have to -- I have to look up the number because I just don't remember what that is.

But I'll fix it.

Q Thank you.

Yes, so to confirm, as you just noted, it is three items on page 2 related to the date of the San Bruno investigation, the FERC docket and the Playa del Rey storage field.

A Right.

Q All right. Thank you very much.

Ms. Felts, do you have any operational experience with gas storage fields?

A No.

Q Have you ever worked for a gas storage operator?

A No.

Q Have you ever done engineering work for a gas storage operator?

A No.

Q Do you have any experience related to the

design or configuration of gas storage wells?

A Not directly, but the design and configuration of wells in general is not so different.

Q What experience do you have with the design and configuration of wells generally?

A I have designed and drilled water wells for groundwater monitoring and --

Well, that's all for generally.

Q Okay. And how deep are those wells usually?

A I think the deepest one was actually -- was probably about -- I'm trying to think, about 400 feet shallow wells.

Q And do they have surface casings?

A Yes.

Q And production casings?

A Yes. Depending on what you're drilling through, you have to design it properly so that you isolate the different sands or lenses, clays; so it just depends on what you're drilling through how you design the well.

Q And do they have tubing and packer configuration?

A Generally not necessary; however, I did study drilling in engineering school.

Q Okay. And when you say you studied drilling, you studied gas storage well design and configuration?

A Gas and oil -- oil and gas well drilling.

Q So gas production?

A It would be gas production, yes.

Q Okay. Do you have experience with gas storage well integrity monitoring?

A Not sure what you mean by that.

Q Well, in your testimony you have discussion about well integrity monitoring, correct?

A Say that again.

Q In your testimony you address SoCalGas's well integrity monitoring programs; is that correct?

MR. GRUEN: Just for clarification, when you're going to be asking about testimony, can the witness be directed where in the testimony she is being asked?

MR. STODDARD: Yeah. We can circle back on that.

Q Ms. Felts, what is your understanding of the phrase "well integrity monitoring"?

A I think that is a phrase that either or both SoCalGas and Blade used.

So my understanding of it, it's the

monitoring of the well for -- to make sure that it is not leaking or has not lost wall thickness from corrosion or erosion, and is behaving or -- as intended.

Q Okay. And do you have experience with that process? Have you personally performed well integrity monitoring?

A Well, that's kind of a weird question because well integrity monitoring, although you would have to have field testing to do, you would -- the monitoring itself would be a matter of record assessment.

So data assessment. So you would hire someone to come out and run the tests on the well.

An engineer would look at the results of the test, and I would guess that the integrity monitoring aspect of it would be on the engineering side where you would be evaluating the data that was generated from the well. And the engineer could call for the tests, and my experience would be in reviewing data.

Q What sort of tests are you referring to?

A Well, could be logs of the well, various types.

Could be a -- the use of a tool like a USITs I think they call it now, to determine the wall

thickness of the well.

Could be a temperature survey, a noise survey, they also have some tests for erosion, involves --

Q And do you have experience interpreting casing inspection logs prior to your work in this matter?

A Yes.

Q What was that experience?

A I've looked at casing inspection logs in a number of cases in the past where there were issues of groundwater contamination, and it would be related to an oil production well or a --

I can't remember a gas production well. I think only oil.

Q Do you recall what sorts of casing inspection logs, what the tool was?

A What the tool was?

It was a tool that would monitor -- it would measure the wall thickness of the pipe, the casing. Typically that would be what I would look for.

MR. GRUEN: I'm sorry, I'm just noting just for timing sake, we can keep going, but I'm wondering if you have an idea when you might like to break.

MR. STODDARD: We can take a break after

probably another 10 minutes.

MR. GRUEN: Does that work for you?

Okay.

BY MR. STODDARD:

Q So your interpretation -- I'm sorry, again.

Do you recall the types of tools that were used in that specific instance related to the oil production well?

A I'm going to say that it was similar to the USIT one that SoCalGas is using, but I don't remember the name of the tool.

Q Okay. Any other experience interpreting casing inspection logs?

A Not that I recall just offhand, no.

Q And in interpreting the -- in interpreting the casing inspection log in that instance, do you recall being present at the time that the log was run?

A I have never been present when a log was run on an oil or gas well.

Q Okay. Do you recall communicating with the wire line operator about running the tool that resulted in a log that you interpreted?

A No.

Q Okay. And do you recall approximately when

that was that you interpreted the log related to the oil production well?

A I recall that there was more than one well that I did this on, and I -- I'm going to say it's probably during the 1990s. I don't have a date.

Q Okay. And again, this was based entirely on review of the records?

A Yes.

Q Okay. Do you have any experience with microbially influenced corrosion?

A Yes.

Q Can you please describe your experience?

A It has to do with underground storage tanks that leaked, pipelines that leaked, everything underground exposed to groundwater that I was requested to look at that leaked.

Q So you have experience with it in a number of cases?

A Yes.

Q Do you recall --

Did you perform any testing or analysis related to MIC?

A No.

MR. GRUEN: Just for the record, "MIC" is what is the --

BY MR. STODDARD:

Q I'm sorry, I'm using the phase "MIC" as the acronym for microbially influenced corrosion.

A Yes.

Q Did you perform any testing or analysis related to MIC?

A No.

Q Okay. Finally, Ms. Felts, do you have any experience with well-control or well-kill operations?

A No.

Q Ms. Felts, do you have any experience with --

You're an attorney, correct?

A Yes.

Q Have you ever been involved in a discovery dispute as an attorney?

A No.

Q "No"?

Have you ever been involved in a privilege review?

Do you understand what I mean by "privilege review"?

A Yes.

MR. GRUEN: I'm going to just --

THE WITNESS: Only as a side --

You know, I'm a consultant, there is a privilege review issue, but I'm not the one that gets involved in settling it.

BY MR. STODDARD:

Q So as an attorney, you've never overseen a privilege review?

MR. GRUEN: All right. For the record, I'm just going to note an objection as to relevance in asking her about her role as an attorney here.

But she can answer the question.

MR. STODDARD: The relevance is her testimony asserts violations related to privilege; so I'm asking her about her scope and experience and knowledge related to the subject matter.

THE WITNESS: I'm familiar with the subject matter. It's generally not my responsibility as a technical consultant.

BY MR. STODDARD:

Q Okay. So you've never prepared a privilege log?

A I don't think that's true. I think I probably have prepared one in the past.

Q You've prepared a privilege log as an attorney?

A No, as a technical --

Q You've prepared a privilege log as a technical consultant?

A Yes. I mean, this is a matter of identifying records, and the condition -- the -- whether or not the records are privileged, and if someone asked me to prepare a log, I could prepare the log.

Q So in that context of preparing a log as a technical consultant, you assess the privilege and then you designate the documents accordingly?

A I don't have to usually assess the privilege because it's usually already assessed before I get to it. Someone has already claimed privilege.

Q And then in reviewing the documents you add them to the log and determine that they fall within the scope of the privilege claim?

A Yes. Or I sort -- sort a stack of them and say these are privileged and these are not.

Q Ms. Felts, can you briefly describe your experience with PUC enforcement investigations, prior experience with PUC enforcement investigations?

A I guess I would have to look back at my resume to see who it was that I was working for on the different cases.

Q Let's do that briefly, and I'll make it

quick, Exhibit 1-2.

First on page 2 of Exhibit 1-2, the OII related to San Bruno, was that an enforcement investigation?

A Yes. Yes, it was.

Q Okay. Next down, the Playa del Rey gas storage integrity case at the bottom of this page, was that an enforcement investigation?

A That was Division of Ratepayer Advocates, so I would say no. That was a reasonableness case.

Q And it was related to a sale of property?

A Yes.

Q And then the next item on the next page, the application of Southern California Gas Company to sell the Montebello gas storage field, that also was an application for a sale of an asset, correct?

A Let me see, Montebello.

Q This is on page 2 of your resume in the second column.

A Oh, okay. Okay. That was also for the Division of Ratepayer Advocates, so that would have been a reasonableness review.

Q And it says there it's an application, correct?

A Yes.

Q Okay. Have you ever worked as an attorney in a regulatory investigation?
A No.
MR. STODDARD: All right. Thank you.
We can take a break.
THE VIDEOGRAPHER: Just a moment, please.
This is the end of disk number one, Volume Number 1, of the deposition of Margaret C. Felts on February 5th of the year 2020.
We are off the record at 10:55 a.m.
(Off the record.)
THE VIDEOGRAPHER: This is the beginning of disk number two, Volume Number 1, of the deposition of Margaret Felts on February 5th of the year 2020.
We are on the record at 11:13 a.m.
MR. STODDARD: Ms. Felts, actually, I'm going to mark Exhibit 1-3.
(Deposition Exhibit 1-3 was marked for identification and is attached hereto.)
BY MR. STODDARD:
Q Ms. Felts, do you recognize this document?
A Yes.
Q Is this your contract with the California Public Utilities Commission related to your work in

this matter?
A Yes.
Q Do you see where it says "Start Date October 21, 2019 or upon DGS OLS approval, whichever is later"?
A Yes.
Q Is that the date that this document was mailed to you?
A What date?
Q Is October 21, 2019 the day that you received the contract?
A I don't know.
Q I'll direct you to the bottom of the document where it shows your signature with the date signed of November 5, 2019.
Do you see that?
A Yes.
Q And on the next page it shows a signature from the Department of General Services with a stamp of November 7, 2019.
Do you see that?
A Yes.
Q Okay. Do you recall whether you received this document weeks prior to the date that you signed it?

A I would have received it --

I think I received it a week before this signature date because I signed one and returned it, and then I was notified about five days later that there was an error in the way it was written. Something was omitted so GSA had sent it back and I re-signed it; so this is the second signature of mine.

So there was an iteration in there about a week's turn around. I don't remember the exact date when I received the first draft of it.

Q Okay. Do you recall how it was transmitted to you?

A By email.

Q "By email."

From --

MR. GRUEN: I'm going to note an objection to the extent that calls for attorney-client privilege.

Notwithstanding, I think you can answer that question, if you're able to.

THE WITNESS: So the process here is that the first draft is provided by email for me to review, and then I would return that, possibly with an electronic -- a scanned version with the signature.

When they get the contract ready to be

signed officially, they mail it overnight mail to me, and I wet sign it. And I send it back by, you know, overnight mail.

BY MR. STODDARD:

Q When you say "they," do you mean the California Public Utilities Commission?

A Yes. The contracts officer, yes.

Q Do you recall who the contracts officer was?

A I think her name was Peggy Owens. Peggy Owens.

Q Okay. Did you correspond with SED personnel related to this contract?

A No.

Q Were you contacted by SED personnel prior to executing this contract related to the engagement?

A I was only contacted by the legal office.

Q Okay. So prior to signing this contract, you had not had any -- strike that.

In connection with this engagement, prior to signing this contract you had not had any contact or communications with SED personnel about this matter?

A That's correct.

MR. GRUEN: Can I just clarify it?

By "SED personnel," can you clarify that term?

MR. STODDARD: Thank you. Yes.

Anyone that Ms. Felts is aware is part of the SED department.

Q In other words, staff that would be assigned to SED or counsel working in this matter representing SED, including Darryl Gruen, Amy Yip-Kikugawa or Nicholas Sher.

A Okay. I had communications with Karen Shea and later with Darryl Gruen after the contract was signed.

Q Okay. So you had communications with Karen Shea prior to the contract execution about your engagement in this matter?

A Yes.

Q Okay. Do you recall if those were email communications?

A They would have been email communications. Maybe a phone call.

Q Okay. I don't believe we have those email communications to the degree there are any.

Ms. Felts, I'm going to direct you to Exhibit A of the contract. It's on page -- it begins on page 3. It's the "Scope of Work."

A Okay.

Q Do you see below where it says "Write

opening reply and rebuttal testimony as an expert witness on behalf of the PUC's Safety and Enforcement Division, and based on results of this analysis testify in relation to that testimony at hearings if necessary."

Is that correct?

A Is that at the bottom?

Q I'm sorry, paragraph 5a.

A Okay. I see it.

Q About halfway down that indented paragraph --

A Yes.

Q -- do you see where it refers to you as an expert witness on behalf of the CPUC Safety and Enforcement Division?

A Yes.

Q And then the next sentence which says in preparation for testimony you will provide extensive review of Southern California Gas Company records as necessary to assess compliance with safety requirements?

A Yes.

Q And then turning to the next page of Exhibit A, this is page 4 of the document.

Do you see where it says in paragraph h that

your scope of work includes discuss, support and review legal briefs, motions and other legal and procedural documents as necessary.

A Yes.

Q And in paragraph i where it States, "When necessary, provide and manage subcontractors who may provide necessary technical services and support to SED"?

A Yes.

Q Are you aware of any subcontractors engaged by SED in this matter?

A Do you want to restate that again?

Q Paragraph i states that "When necessary, provide and manage subcontractors who may provide necessary technical services in support to SED."

Do you see that?

A Yes.

Q Are you aware of any subcontractors in this matter?

A Those would be subcontractors to my contract?

Q Or to SED.

A I would not know what SED is doing, but I believe this has to do with if I hired someone to help me as a subcontractor.

Q I'm not asking about your interpretation of the provision so much as asking whether you have been doing work related to providing or managing subcontractors related to technical services in support to SED in this matter.

MR. GRUEN: I'm going to object to that as overly broad, just to the extent it calls for subcontractors which are outside the scope of Ms. Felts' contract.

So one option is to restate that. Or if you want, you can ask her to answer as you've worded it.

MR. STODDARD: I would ask --

Okay, I'll restate in a few different questions.

Q One is have you engaged any subcontractors pursuant to your contract?

A Not yet.

Q Okay. Have you worked with any other subcontractors in this matter engaged by SED?

A No.

Q Do you intend to engage any subcontractors?

MR. GRUEN: I'm going to object to the extent that calls for attorney work product privilege.

And I'm going to instruct the witness not to answer the question.

It also may -- just for the record, that may involve attorney-client privilege as well.

BY MR. STODDARD:

Q Okay. Ms. Felts, what did you do today to prepare for today's deposition?

Did you review any documents?

A I read through the opening testimony.

Q Did you meet with anyone -- I'm not asking you to divulge attorney-client privilege information.

Did you meet with anyone aside from your counsel?

A No.

Q Did you review the exhibits relied upon in your opening testimony?

A I reviewed some of them.

Q Did you review any discovery, data requests and data responses?

A Yes.

Q Do you recall which ones?

A I couldn't give you an exact list, but I looked at some well files.

Q Do you recall which wells the well files related to?

A Well, I assessed 25, 25-A, 25-B, 6, but I'm not sure if it was an SS-6 or another one.

Q Okay. Did you prepare any written materials in preparation for this deposition?
A No.
Q And I apologize for jumping around, but I'm going to refer back to -- it's not exactly necessary, but I'm referring back to your contract which is Exhibit 1-3, and I would just like to confirm do you have any other current contracts with the California Public Utilities Commission?
A No.
Q Do you have any other current contracts with the State of California or any agency or department --
A No.
Q -- thereof?
A No.
Q At the time that you were engaged in your contract, did you understand the scope of your work to be to provide expert testimony in this matter?
A Yes.
Q What did you understand the scope of issues you were to address to be?
A What's described here in this scope of work. That is what I was asked to do.
Q Did you believe that it related to records

review?
A Yes.
Q Did you have prior awareness of the Aliso Canyon incident?
A Yes.
Q Had you reviewed records related to the Aliso Canyon incident prior to your engagement?
A I did not have access to anything other than what was publically available.
Q Did you review what was publically available?
A Yes. I had a file I was collecting stuff in.
Q When did you begin collecting stuff?
A About the time the incident began.
Q Why were you collecting stuff?
A Well, historically I usually get called sooner or later on these things; so I had an interest in it.
Q So you expected to be appearing as an expert witness in this matter before you were engaged by SED?
A Well, it was a possibility. And I'm a consultant.
Q Do you recall the sources that you went to

for those public records?

A Well, I signed up for SoCalGas's regular news, the little news releases that came out, came across, I think on email. I started following a different proceeding having to do with the potential closure of the gas storage unit. And so I --

When I went to the PUC and signed -- you know, electronically signed up for -- to be a party -- not a party, but to receive the information on that case -- and I don't remember the case number, I'm sure you know it --

So I received regular information about that case and kind of followed it. And may or may not have kept records that came through from that.

Q But you -- I mean, you said you "collected" it.

Did you save it in a file on your desktop?

A I would have -- I don't --

I think I probably just saved the emails that came in an email file folder.

Q Okay. And did you review these materials when you were preparing your testimony?

A No. They're not useful for this.

Q Why not?

A Well, I have plenty of data that has come

through discovery on this case to look at without going to some other source right now.

Q Okay. Aside from the scope of work described in your contract, were you engaged in any other capacity by SED to work on this matter?

A No.

Q Has SED utilized you in any other capacity in your work on this matter?

A No.

Q Ms. Felts, were you involved in SED's preliminary investigation related to the Aliso Canyon's incident prior to the initiation of the formal OII?

A No.

MR. STODDARD: I'm going to mark Exhibit 1-4.

(Deposition Exhibit 1-4 was marked for identification and is attached hereto.)

BY MR. STODDARD:

Q Ms. Felts, do you recognize this document?

A Yes.

Q This is an email from Mr. Gruen to you and Ms. Shea sent on Friday, November 8th at 9:19 a.m.; is that correct?

A Yes.

MR. GRUEN: If I may, I just noticed, I'm noting that because the document is identified as Public Utilities Code Section 583, that to the extent questions elicit information from Ms. Felts that are protected by PU Code Section 583, we would look to SoCalGas to properly mark that as confidential.

MR. STODDARD: Understood.

Q And Ms. Felts, it appears that this included attachments which were transcripts of examinations under oath conducted by SED; is that correct?

A Yes.

Q Is this the first email that you received from SED in connection with this matter?

A Well, I'd say November 8th would be -- it would have to be the first, or there may have been others that came on that date. I didn't receive anything before this.

Q Earlier you stated you had email communications with Ms. Shea prior to your execution of the contract.

A Well, I think I did about the contract, that was -- she was handling that coordination with the contracts office with Peggy.

MR. STODDARD: Okay. Darryl, while we're on the record, if you'd like us to submit a written request

or follow up with our prior request for all communications, we can do so.

But I prefer to just state it on the record that you confirm the date of the first email communications and produce any additional communications between Ms. Felts and SED personnel or SED counsel.

MR. GRUEN: Yeah. I mean, I think we would like to have -- it's noted for the record, of course.

But we appreciate having something in writing as well if there is an indication that there is something that you have not received.

MR. STODDARD: Okay.

MR. GRUEN: And perhaps just for our understanding if you think that's the case, if you could clarify the dates, just so we understand what dates you're looking for.

MR. STODDARD: We appreciate that. We'll provide that. We don't know the dates of prior emails, which is what we're getting at.

MR. GRUEN: Okay.

BY MR. STODDARD:

Q Since your initial engagement, who have been your primary points of contact for SED?

A Darryl and Karen.

Q "Darryl and Karen"?
Have you also spoken with Mr. Sher, Nicholas Sher, counsel of SED?
A No, not yet.
Q Have you emailed with him?
A No.
Q How about Randy Holter?
A Don't --
I don't know who that is.
Q You don't know who that is.
Matt Epuna?
A No.
Q E-P-U-N-A?
A No.
Q Maria Solas?
A Maria Solas.
No.
Q Lee Palmer?
A No.
Q Bear with me, I'm going to ask some more names.
Amy Yip-Kikugawa?
A I know Amy. I have not communicated with her in years.
Q You know her from prior matters?

A Yes.
Q Is that from San Bruno?
A I think so, yes.
Q How about Ken Bruno?
A No.
Q Jack Mulligan?
A No.
Q Mitch Chafsome?
A No.
Q Have you communicated with anyone from the California Advocates office, the Public Advocates Office, formerly know as the Division of Ratepayer Advocates and several other names?
A Yeah, I was going to say --
Q Have you communicated with anybody from Cal Advocates relating to this matter since you were engaged?
A No.
Q Have you communicated with anyone from Cal Advocates about this matter before you were engaged by SED?
A Ever?
Q Related to the Aliso Canyon incident, to your knowledge.
A No.

Q And since you were engaged have you spoken with Blade, anyone from Blade Energy Partners?
A No.
Q Before you were engaged but following the Aliso Canyon incident, did you have any contact or communication, to your knowledge, with anyone from Blade Energy Partners?
A No.
Q Okay. So based on what you said earlier, and correct me if I'm wrong, it sounds like your only points of communication with SED have been Darryl Gruen and Karen Shea; is that correct?
A Yes.
Q And you communicate via email?
A And phone.
Q And phone; do you text, text message?
A I sent Darryl a first text message this morning to tell him that I got here.
Q Okay. Do you communicate by via mail, hard copy?
A No.
Q "No."
In-person meetings?
A No. I live in Colorado. This is the in-person meeting.

MR. STODDARD: Okay. I'd like to introduce Exhibit 1-5.

(Deposition Exhibit 1-5 was marked for identification and is attached hereto.)

BY MR. STODDARD:

Q Ms. Felts, do you recognize this document?

A Appears to be an email to me.

Q That is correct. It's an email from Darryl Gruen to you on November 8th, the same day as your first -- well, the same day as the prior email that we discussed --

A Yes.

Q -- related to the EUO transcript.

And this one, the subject line is "Scoping Memo Recordkeeping Language."

At that time was it your understanding that you were being engaged for the purposes of assessing SoCalGas's recordkeeping practices?

A I think that was part of the engagement, yes.

Q Was it your understanding that that was your primary purpose of your engagement in this matter?

MR. GRUEN: Objection. Just use of the word "primary" is vague.

Can you clarify?

MR. STODDARD: Sure.

Q At the time of your initial engagement, and we'll have to be a little bit -- you know, within the first few days of signing the contract, during your initials discussions with SED, was it your understanding that you were being engaged based on your experience with recordkeeping in other utility investigations?

A I think my understanding was that my recordkeeping experience was important to them to be able to look at recordkeeping issues, but also to look at other issues that had arisen through the Blade investigation.

Q Do you recall asking Darryl to send you the specific scope language related to the recordkeeping issue?

A You're asking me if I sent him an --

Q It appears --

A -- email before I got this?

Q Yeah, whether an email or a phone call.

It appears that this email was sent -- there is no context for this document.

A And I don't remember a context to it. I don't remember why he would send me only the

paragraph 4, especially since I think it's in the contract.

Q Do you recall having a phone call about it?

A It's possible. It's possible because he called me right as soon as the contract was signed, and we both received copies of the contract by email; so it's possible that there was some discussion and he sent this as a result of a request or something or maybe clarification. I'm not sure.

Q Okay. Approximately how frequently do you communicate with either Darryl or Karen?

MR. GRUEN: I'm going to just object to the extent that that calls for attorney-client and attorney work product following the publication of the opening testimony.

But to the extent that we're talking about communications prior to the publication of the opening testimony, she can answer.

BY MR. STODDARD:

Q Prior to the publication of the testimony, how frequently did you communicate with either Darryl or Karen? I mean approximate.

A So after the contract was written -- was signed, I -- my communications with Karen diminished to only being able to get access to databases at the

PUC. There was some logistics that was involved in doing that, and I was having difficulty remotely; so that's what was happening there.

And then -- and when the contract was signed, then I heard from Darryl. And I would say we probably communicated daily between then and when the opening testimony was sent. But I don't know exactly. I looked at all of the emails that Darryl copied to you, and as far as I know, that was complete -- a complete set.

Q So daily communications could have been phone and email?

A Possibly, yes.

Q Do you recall multiple times a day?

A Possibly during that period of time because it was a very short lead time. I was trying to look at as much stuff as I could before the testimony was due to be filed.

Q You mentioned having trouble accessing databases at the PUC.

A Yes.

Q Do you recall the specific databases?

A There is a database called Diamond buried somewhere in their system.

Q What kind of database is that?

A It's the one where all of your responses were supposed to be housed.

Q That's a file management system?

A Yes.

Q And you had to be granted access to it because you were remote?

A Well, all of the data in response to data requests was provided to the PUC, I guess, either by email or -- and/or thumb drives. That information was all uploaded to this database at the PUC on their mainframe. And the idea was for me to be able to call in and review records there remotely.

It was obviously too voluminous to print out and send me boxes of paper; So I did receive the responses to DR 16 in paper. I believe Karen sent that to me.

Q Do you recall about when you successfully gained access to the PUC's database?

And, again, I'm not asking for a specific date here; it's more relative to your engagement or your opening testimony.

A I would say sometime right around the time the testimony was filed.

Q Before? After?

A I don't know without looking back at the

dates on the -- on the emails, but I would say maybe a couple of days before.

Q Okay. And before you gained access to the Diamond database, any documents that you would have been -- that SED would have transmitted to you would have been via email?

A No. I don't think I got any data responses by email before then.

I had the Blade reports, which was a lot of reading and review. And so I had -- I had the transcripts that were emailed to me that you just saw in this last email.

And then I had the paper copies of DR 16 to look at, which included a set of the daily reports for Boots & Coots drilling. And I think that's primarily what I had to look at initially, which --

And so a full set of the Blade reports included all of the supplemental reports; so it was a complete set of the volumes of that.

Q And did the PUC -- or SED, I'm sorry.

Did SED share anything with you via FTP?

A Not at that time. I didn't have an FTP access until probably at least three weeks after my contract started, and then I was able to FTP large files.

Q The Blade report, where did you obtain that on the Aliso Canyon's web page?

A No, I couldn't download it, but I had tried actually when they started to talk about the contract, and the only thing I could get was the main report; so the rest of it was mailed to me in hard copy. Karen sent it to me.

Q Okay. Was anything else mailed to you in hard copy?

A The responses to DR 16.

Q Okay. Do you recall the approximate date that you received the Blade report in the mail?

A I think it was mailed overnight mail right after the contract was signed.

Q And you reviewed it after you received it?

A Yes.

Q Do you recall how long it took you?

A There are days when I'm still reading on it.

Q Did you review other preliminary investigation -- preliminary SED investigation records aside from the documents that we've just discussed --

A No.

Q -- prior to preparation of your opening testimony?

"No"?

So the records produced by SoCalGas would have been limited to those that were shared with you by SED between the contract date and the date of your opening testimony?

A I -- I had to have had access to the Diamond database at least a couple of days before because I spent at least a day looking through the SS-25 well file. And it was the first file that was provided to -- in response to a data request. I think it must have been in response to the Data Request 1.

It was a file of individual -- each page was an individual PDF. That is the well file that I reviewed before the opening testimony was filed.

Q Do you recall reviewing any other records in the Diamond database aside from the well file prior to your -- to service of your opening testimony?

A I believe I read there was -- there were copies of the Data Request 1 and a Data Request 1 that was SED and D-O-G -- DOGGR, and Data Request 2; so I think I only reviewed the response attachments, the data, for DR-1.

Q Thank you.

Did you review the Public Utilities Code prior to preparing your opening testimony or prior to

serving your opening testimony?

A I reviewed Section -- is it 451? The safety section, whichever that one is.

Q That's it?

A That's it.

Q Did you review the Commission's Rules of Practice and Procedure?

A No.

Q Did you review any internal SED legal research or analysis?

A No.

Q Since you've been engaged by SED, we talked about the scope of work a little bit earlier in your contract.

Since you've been engaged by SED, have you assisted with preparation of any pleadings?

A No.

Q Data requests?

A Yes.

Q Data responses?

A Yes.

Q Did you review any draft SED reports related to findings of their preliminary investigation?

A What would that be?

Q Any documents that include findings,

summaries of evidence, alleged violations.

A Other than the draft filing, the draft opening testimony?

Q Other than the draft opening testimony.

A No.

Q Earlier we were talking about the Blade report. I'm going to briefly check to just see if you've had any contact with any of the individuals.

Will you allow me to just name the names?

If she doesn't know them, she doesn't know them. If she does, she does. I'm not going to enter this as an exhibit right now.

MR. GRUEN: No objection.

BY MR. STODDARD:

Q Ms. Felts, do you know Ravi Krishnamurthy?

A No.

Q Have you ever spoken to Mr. Krishnamurthy?

A No.

Q Have you ever had email contact with Mr. Krishnamurthy?

A No.

Q How about Nigel Alvares?

A No.

Q Greg Asher?

A No.

Q William Bacon?
A No.
Q Miodrag Bogdanovic?
A No.
Q Ismail Ceyhan?
A No.
Q Ming Gao?
A No.
Q Bill Whitney?
A No.
Q Shree Krishna?
A No.
Q Are you familiar with Ecolise, an entity named Ecolise?
A No.
MR. GRUEN: I'm sorry, can you clarify, is that a person?
MR. STODDARD: No, that's a company. Ecolise.
MR. GRUEN: Okay.
BY MR. STODDARD:
Q Liz Summer, do you know her?
A No.
Q How about Jerry Shursen?
A No.
Q Or GSM Oil Field Services?

A No.
MR. STODDARD: We're going to introduce Exhibit 1-6.
(Deposition Exhibit 1-6 was marked for identification and is attached hereto.)
BY MR. STODDARD:
Q Ms. Felts, have you seen this document before?
MR. GRUEN: I'm sorry, can we just give the witness an opportunity to review this?
MR. STODDARD: Yes.
THE WITNESS: I don't think I've ever seen this.
BY MR. STODDARD:
Q Okay. It's an email from Bob Pilko to Randy Holter and Bill Whitney with Ravi Krishnamurthy, Cyndy Reed and PV Suryanarayana copied, and it's from January 28, 2016.
Do you know, have you --
Do you know Bob Pilko?
A No.
Q Have you ever had contact with Bob Pilko?
A No.
Q Do you see below where it states --
It's an email from Randy Holter and says

"Hello Bob, I want to introduce myself for as the Lead Investigation for the CPUC on the Aliso Canyon Storage Facility SS-25 Well Leak."

A Yes.

Q Were you aware that Randy Holter was the lead investigator for SED on the matter?

A No.

MR. GRUEN: I'm going to just object to that as the characterization is vague as to time; so just the question was asked in the present tense.

BY MR. STODDARD:

Q Are you aware that Mr. Randy Holter at any period of time is or was the lead investigator in the Aliso Canyon matter?

A I don't really know anything about the case prior to me coming on it.

Q And you earlier said you haven't had any contact with Mr. Holter, correct?

A I don't know who that is. No.

Q Okay. Are you aware of any other individual for SED being identified as the lead investigator or having the role of lead investigator at this time?

A Right now?

Q Yeah.

A I don't know who might have that

designation.

MR. STODDARD: Okay. I'm going to introduce Exhibit 1-7.

(Deposition Exhibit 1-7 was marked for identification and is attached hereto.)

BY MR. STODDARD:

Q Ms. Felts, do you recognize this document?

A Yes.

Q This is your --

This is the opening testimony of SED in the Aliso Canyon investigation proceeding, correct?

A Yes.

Q And if you look at the top left corner it identifies the docket number, the commissioner, the administrative law judge.

It does not identify you as the witness; is that correct?

A Right.

Q And there is no witness identified; is that correct?

A Looks like that's correct.

Q Do you have any changes to your testimony at this time?

A No.

Q You said you reviewed this in preparation for today's deposition, correct?
A I reviewed part of it.
Q Which part?
A Let's see if I can find it.
Starting at page 51 I read that last night.
Q Okay. So you started reviewing the testimony immediately after the sections that deal with the Blade report; is that correct?
A Yes.
Q Why didn't you review the sections that deal with the Blade report?
A I felt like I could answer questions about that so I didn't need to refresh my memory.
Q Okay. Did you write this?
A No.
Q Who did?
A Well, let me take that back.
I wrote part of it. I wrote the recordkeeping section. And the rest of it was already drafted when I arrived on the scene.
Q Do you know who wrote it?
A No.
Q Who did you receive it from?
A Darryl.

Q Did you ask who wrote it?
A No.
Q So you didn't want to speak with the person who prepared the testimony to ask them questions about why they included certain information?
A I just read it and felt like I understood what they were writing about. I didn't feel it was necessary to track down authors.
Q But you are sponsoring it as your own testimony, correct?
A I was asked to sponsor it. I read it and I said that I could sponsor it, and so I am.
Q The entirety of the testimony?
A Yes.
Q Okay. It includes --
I mean, it's approximately 80 pages, is that correct, 82 pages?
A Yes.
Q And it includes close to 500 footnotes?
A Yes.
Q Did you review and confirm each of the footnotes?
A I read the footnotes. I did not verify them all. Some of them I went to the source, others I did not.

Q So for everything that is cited in here, you reviewed the document that it was cited to?

A I'd have to look at every footnote to answer that question. Is that what you're asking me?

Q Well, I'm asking whether you were approached to getting yourself comfortable in sponsoring this report included reviewing all of the evidence -- alleged evidence that is relied upon in the document.

A There may be a couple of footnotes that I didn't verify, but generally everything that is tied to the Blade report I verified. If there is something else in here that didn't look like it was necessary for me to verify it, I didn't. There may --

I think there are supporting documents that --

Q The exhibits?

A -- that I reviewed.

Yes, the exhibits that went along with it, which would be, say, in the section that I was reviewing last night, there were some letters and exhibits that were provided, and I did read those.

Q Did you review all of the exhibits?

A Yes.

Q Last night or prior to --

A No, prior to the testimony right now.
Q Prior to the service of testimony?
A Yes.
Q Did you review those exhibits -- strike that.
Did you --
You didn't speak to Mr. Mansdorfer, correct?
A No, but there is an EUO of Mansdorfer that I read.
Q So you reviewed all of the EUOs?
A I didn't review them all. I think there are still two or three that I have not read completely, and one of those is Brett Lane, and I don't know, maybe Volume 2 of Brett Lane, and I'm not sure about -- but I'm pretty sure there is at least two others that I haven't read.
Q Do you recall if you've reviewed the Boots & Coots witness EUOs?
A Yes, I did.
Q In the process of preparing or getting yourself comfortable with sponsoring the testimony prepared by others, did you keep any handwritten notes?
A No. I just read -- it was very fast paced review because I didn't have much time.

So I was working primarily with the Blade report and with this document to make sure that they were properly drawing -- drawing conclusions out of the Blade report to this report and that things weren't being misstated.

Q So you worked to confirm that things weren't being misstated relative to the Blade report?

A Right, yes.

Q You weren't concerned with whether or not the Blade report itself was consistent with the evidence or the facts that have been presented in other records in the proceeding?

A So I had very little time and very difficult -- and a lot of difficulty getting access to data that had been provided by SoCalGas. In fact, a lot of the files that I was trying to open, and to this day I can't open, they say that the files were corrupted; so I didn't have access to all of the response data that SoCalGas said they provided.

And the best I can do is with my technical knowledge in reviewing the Blade report and just validating in my own mind that what they were doing made sense, and I did review the daily reports with Boots & Coots and compared that to what Blade said had happened. And I just checked to make sure that

what was drafted in the opening testimony relative to the Blade report accurately reflected what Blade said.

Q And you were comfortable with that process?

A Well, it was the best I could do in the amount of time I had available. If I had had more time, I would have looked at all of the data and written my own report. But I didn't have that luxury.

Q When you were initially engaged, did you have an understanding of the timeline?

A I knew when the opening testimony was due. I knew they were hoping to get some testimony from me, but as the date drew closer, it was -- it was at least possible in my mind that I wouldn't be able to produce testimony in that period of time.

Q In part because of the technical difficulties with accessing records?

A And the fact that the contract wasn't signed; so, you know, the date when it was due wasn't changing, and I wasn't engaged yet. So there is only so much you can do in a couple of weeks' time.

Q So did you begin work prior to --

Did you begin substantive work in this case prior to execution of the contract?

A No.
Q So your concern with the delay in the execution of the contract was you understood that you had testimony due on a date certain --
A Right.
Q -- but that you weren't going to start looking at records until after the contract was done?
A Right.
Q So you wouldn't start substantive work or communicate with SED until after the contract was done?
A Exactly.
Q And did you understand at the time that you were engaged that there was already draft testimony that had been prepared?
A I think Darryl told me that they were working on a draft when he called me and the contract was signed; so before that, I didn't know that they were drafting anything.
Q And did he tell you or describe the scope of violations or issues that your testimony would be addressing?
And I don't mean the scope of work contractually. I mean the scope of issues that is in your testimony substantively.

A I'm sure we talked about that.
Q Okay. You indicated you didn't keep any notes, but in reviewing documents, you said mostly you read.
Did you mark up documents, underline, keep margin notes?
A Excuse me. Just a second.
I typically don't mark documents. I rarely highlight anymore. And sometimes I use sticky notes.
THE VIDEOGRAPHER: You've lost your microphone.
THE WITNESS: I'm sorry.
THE VIDEOGRAPHER: It's just off the clip there.
THE WITNESS: Sometimes I use sticky notes to mark pages.
BY MR. STODDARD:
Q In this case you used sticky notes to mark pages?
A Like a tab, you know?
Q Right.
A Yes.
Q And do you recall highlighting any documents in this?
A I don't believe there is any highlights in any documents.
Q Okay. And did you collect records that you

had marked with highlights or sticky notes and provide them to SED in connection with a request for work papers?

A Well, there weren't any highlights, and so a sticky note thing, I would just tab a page so I would go back to it, and I typically reuse those tabs so there wouldn't be any way to recover that as something to send to you.

Q What do you mean "reuse"?

You put them on the document and then you take them off the document?

A Yeah, I reuse them.

So I mark documents -- I mark pages that I want to go back and look at. Once I go back and look at it, I pull it off, put it in my sticky note pad and reuse it somewhere else.

Q So does your copy of the Blade report that is sitting at your home today have sticky notes on it?

A No. There is no sticky notes in my Blade report right now.

Q Do you think any of the documents that you have at your home in hard copy related to this investigation presently have sticky notes on them?

A They might presently, but they would be

documents that I didn't have prior to the filing of the initial testimony.

Q Okay. We can take a break after -- just one more question and then we can break for lunch.

The sticky notes that you use, are they like this kind, Post-it notes?

A Yes.

Q Well, I wasn't sure if it was like that or a blue kind, like a flag.

A No, I don't have the little blue kinds. I only have yellow ones.

Q For the record, Ms. Felts indicated that she uses the little Post-it notes.

Do you write on them?

A No, not often. I mean, if I wrote something on it, it would be like a -- something that says "Read this again."

Q Do you recall writing anything on any sticky notes in this case prior to the service of your opening testimony?

A No, I don't even think I used sticky notes prior to the opening testimony.

Q Since service of the opening testimony?

A It's possible there is something written on some note somewhere.

Q Okay. And aside from that, you haven't kept any other notes, handwritten, electronic --

A You're asking me --

Q -- or otherwise?

A -- prior to the opening testimony being filed?

Q Yes.

A You have everything I had, which is whatever Darryl sent you.

MR. STODDARD: Okay. Let's take a break for lunch. Come back at, let's say, 1:15. Let's make it 1:10 and we'll get started at 1:15.

MR. GRUEN: That sounds reasonable.

THE VIDEOGRAPHER: This is the end of disk number two, Volume Number 1, of the deposition of Margaret Felts on February 5th of the year 2020.

We are off the record at 12:15 p.m.

(Lunch recess.)

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Investigation on the Commission's Own Motion into the Operations and Practices of Southern California Gas Company with Respect to the Aliso Canyon Storage Facility and the release of natural gas, and Order to Show Cause Why Southern California Gas Company Should Not Be Sanctioned for Allowing the Uncontrolled Release of Natural Gas from Its Aliso Canyon Storage Facility. (U904G).	I.19-06-016 (Filed 6-27-19)

DEPOSITION OF MARGARET C. FELTS
Los Angeles, California
Wednesday, February 5, 2020
AFTERNOON SESSION

Reported by:
LINDA RYAN
CSR No. 9915
JOB No. 311652

Los Angeles, California
Wednesday, February 5, 2020
1:24 p.m. - 8:39 p.m.

THE VIDEOGRAPHER: Here begins disk number three, Volume Number 1, of the deposition of Margaret Felts on February the 5th of the year 2020.

We are on the record at 1:24 p.m.

MR. GRUEN: I'm terribly sorry. Could we go off the record for just a moment, would that be okay?

MR. STODDARD: Yes.

THE VIDEOGRAPHER: Just a moment, please.

We are off the record at 1:24 p.m.

(Off the record.)

THE VIDEOGRAPHER: We are back on the record at 1:24 p.m.

MR. GRUEN: While we were off the record we just had clarified that during the lunch break, Ms. Felts had refreshed her recollection as to her role regarding the item on her resume, entitled the "PG&E General Rate Case FERC Docket No. ER 16-2320-000," and she is prepared to make a statement for the record as to her role updating the information she provided this morning.

BY MR. STODDARD:

Q Okay. And for the sake of clarity, this relates to Exhibit 1-2; is that correct?
A Yes.
Q Go ahead.
A Okay. So on that case the only thing I did was help with some discovery and reviewed the responses to that discovery, and I believe I sat in on one interview.
Q And by "interview," do you mean deposition?
A It was actually something informal. It was not a deposition.
Q And you were retained as an consulting expert?
A Yes.
Q In what capacity? What was the scope of your work?
A It had to do with electric utility issues. And, honestly, without looking back at the file, I couldn't tell you exactly what it was that we were looking at.
I remember that I was doing discovery. I did not file testimony, did not write anything.
Q And your client was the California Public Utilities Commission?
A Yes.

Q And do you recall what the case concerned?
A So it was a rate case, so there must have been some subset of the rate case that they needed expertise on that I could provide; so I didn't -- I don't think I billed very much on that case.
Q What discovery questions do you recall preparing?
A None. I would have to look at a file to see.
Q Do you remember the general subject matter?
A No. I don't really remember too much about it.
Q Okay. But it didn't relate to natural gas storage facilities?
A It had nothing to do with natural gas.
Q Okay. And otherwise that entry is accurate on your resume?
A Yes.
Q Except for the spelling of legal office.
A Okay, I'll correct that.
Q All right. Thank you for that.
So I have another couple of questions I'd like to circle back on that relate to a few other topics that we covered prior to lunch.
And the first is we talked a little bit

about your work since you were engaged by SED prior to service of your opening testimony and who you spoke with or have spoken with related to your work preparing testimony for the Aliso Canyon matter.

You indicated you hadn't spoken with anybody at Blade, correct?

A That's correct.

Q And you indicated that you hadn't spoken with any other subcontractors, you know, working for SED or for you prior to service of your opening testimony, correct?

A That's correct.

Q Okay. Have you spoken with any other technical experts related to your work on this matter --

A No.

Q -- whether engaged by the Commission or not?

A No.

Q Have you spoken with anybody at SoCalGas about your work on this matter?

A No.

Q Have you spoken with anybody at SoCalGas about the Aliso Canyon incident generally?

A No.

Q Have you spoken with anybody at DOGGR about

the Aliso Canyon incident?
A No.
Q Have you spoken with anybody at the California Energy Commission about this incident?
A No.
Q The Governor's office?
A No.
Q State Legislature?
A No.
Q Okay. Thank you.
And to clarify, that was the California State Legislature. I know you're a resident of Colorado.
A I haven't spoken with anybody in either state.
Q Is your answer the same?
A Yes.
Q Have you spoken with anybody who is employed by the County of Los Angeles?
A No.
Q The Department of Public Health in Los Angeles?
A No.
Q Any federal authorities or public officials?
A No.

Q Okay. Any other government officials in any jurisdiction or any agency about the Aliso Canyon matter that you're aware of?

A No. I haven't actually talked to anyone about this case.

Q But --

What about prior to your engagement in this matter by SED, you know, understanding that it goes back a little ways, do you recall any significant discussions that may be relevant to your testimony?

A Nothing relevant to my testimony. At some point maybe a year ago I might have spoken with Darryl Gruen about the case coming up or that it may be it was already in the works. I'm not sure. But we were working on San Bruno; so I probably mentioned the case to him at some point in time that I would be interested in working on it.

Q Okay. So you reached out to Darryl to indicate an interest in helping out on the case?

A Yes. It was a long time before they actually called me and asked if I would do it, work on it.

Q Do you recall the contents of that communication --

A No.

Q -- what you said?
A I probably just said "Gee, Darryl, I'm a petroleum engineer in a former life, and I would be really interested in working on this Aliso case."
Q And how did Darryl respond?
A He probably told me they were handling it internally because I didn't hear back about it; so just, you know, a consultant reach out.
MR. STODDARD: Thank you.
I'd like to introduce Exhibit 1-8.
(Deposition Exhibit 1-8 was marked for identification and is attached hereto.)
BY MR. STODDARD:
Q Ms. Felts, do you recognize this document?
A Yes.
Q This is a data request from Southern California Gas company to SED. And if you can refer to page 3, please, there is a single request.
Do you see that?
A Oh, right, yes.
Q It says "Identify the sponsoring witness(es) for SED's Opening Testimony."
A Yes.
Q Did you help prepare the response to this

question?

A No.

Q Did you review the response to this question?

A Not until after it was filed.

MR. MOSHFEGH: That's a different one.

MR. STODDARD: I'd like to introduce Exhibit 1-9.

(Deposition Exhibit 1-9 was marked for identification and is attached hereto.)

MR. STODDARD: I apologize, Ms. Felts. I'm going to restate one of my last questions because I realized you didn't have this document in front of you.

Q Just to confirm, my prior question is related to the data request from SoCalGas, which identified the question on page 3.

And also if you can please reference on page 2 of the SoCalGas data request paragraph 3 identifies a response deadline by close of business on December 6, 2019.

Do you see that? Paragraph 3 on page 2. It's the first at the top of the page.

A Okay, yes.

Q It has the deadline.
A I see that.
Q And it states the deadline is December 6, 2019, which was a few weeks after your testimony was served, correct?
A Yes.
Q Now, please refer to what we've marked Exhibit 1-9.
Do you recognize this document?
A Yes.
Q Did you help prepare this response?
A No.
Q Did you review this response?
A Not until after it was filed.
Q And this states that the sponsoring witness for SED's opening testimony is Ms. Margaret Felts; is that correct?
A Yes.
Q Did SED consult you about this before they served it?
A Well, they --
Q They filed it?
A They asked me to sponsor the testimony before it was filed, if that's what you're asking. The data response itself was handled, I assume, by

Darryl Gruen.

Q So why wasn't your name on the opening testimony that was served by SED?

A Well, since I didn't prepare the cover page, I can't answer that. It was filed by the PUC. I assume that might have been an oversight because I had agreed to sponsor it before it was filed.

Q Did you discuss the fact that your name wasn't on it?

A I didn't know until --

Q After the fact.

A I actually didn't know -- notice it until you just put it in front of me and said that it was empty, that it was blank. I don't even know if I ever had a printed copy of the cover. I might only have an email copy of the document.

Q So there was no discussion about whether they could identify you as their witness on the document prior to service?

A Well, there was discussion prior to service, and I agreed that I would sponsor it.

MR. STODDARD: Okay. I'm going to introduce Exhibit 1-9.

THE WITNESS: That's what I have in front of me.

MR. STODDARD: I apologize, I have to get these

Post-its off.

Exhibit 1-10.

(Deposition Exhibit 1-10 was marked for identification and is attached hereto.)

BY MR. STODDARD:

Q Do you recognize this document?

A Yes, I've seen it before.

Q If you'll turn to page 3.

A Okay.

Q You'll see the first data request at the bottom is "Identify the date on which SED retained Margaret Felts in connection with the Proceeding."

Do you see that?

A Yes.

Q If you'll turn to page 4 on the back, question 2 is "Identify the date on which Margaret Felts agreed to adopt the entirety of SED's Opening Testimony."

Do you see that?

A Yes.

Q And Commission 3 requests your statement of qualifications.

Do you see that?

A Yes.

MR. STODDARD: I'm going to mark and introduce Exhibit 1-11.

(Deposition Exhibit 1-11 was marked for identification and is attached hereto.)

BY MR. STODDARD:

Q Do you recognize this document?

A Yes.

Q Did you prepare this data response?

A No.

Q For purposes of the record, this is SED's data response to SoCalGas's data request for Exhibit 1-10.

And you see question 1, 2 and 3 from the prior data request restated there?

A Yes.

Q And SED's response was that SED contracted with Ms. Felts in connection with this proceeding on November 7, 2019, correct?

A That's correct.

Q And it states in response to question 2 that you agreed to adopt the entirety of SED's opening testimony on approximately November 17, 2019; is that correct?

A I think that's correct.

Q Which was approximately five days prior to service of your testimony, correct?
A Yes.
MR. STODDARD: I'd like to introduce Exhibit 1-12.
(Deposition Exhibit 1-12 was marked for identification and is attached hereto.)
BY MR. STODDARD:
Q Do you recognize this document, Ms. Felts?
A Yes.
Q What is it?
A A report from the San Bruno case. It was the first one that was filed in March 12, 2012.
Q So this was your opening testimony in the San Bruno case?
A Yes.
Q In which PG&E was a defendant?
A Yes.
Q And it states on the cover document clearly that it is the report and testimony of Margaret Felts, correct?
A Yes.
Q Did you write this testimony?
A Yes.

Q Do you recall approximately when you were engaged by CPSD for purposes of preparing this testimony?

A Let me look at my resume. It's probably on there.

2011. I don't have the day, the day and month.

Looks like February 2011. It would have been sometime shortly after that.

Q February 2011?

A Sometime shortly after that because that's the date of the OII.

Q Okay. So approximately a year before your testimony was served?

A Yes.

Q And do you recall who your point of contact was at SED, then I think CPSD?

A Initially it was Bob Cagen.

Q "Bob Cagen."

And do you recall reviewing SED's investigation records for the purposes of preparing your testimony?

A In this case?

Q Uh-huh.

A No.

Q "No."
What generally do you recall in terms of your process related to preparing this testimony in this case? What did you review generally?
A Well, PG&E data that was submitted to the Commission.
Q So by "data" you mean records and documents?
A Yes.
Q Did you also review the NTSB report?
A Yes, I did.
Q Did you review an SED report?
A An SED report?
Q A report or document from SED related to their findings in this matter.
A I don't remember an SED report. There could have been one. There was a lot of -- a lot of records that I looked at.
Q And do you recall who your point of contact was at SED after Bob Cagen?
A Darryl Gruen.
Q And in this case did either Bob or Darryl hand you a prepared draft of this testimony when you --
A Of this testimony?
Q Yes.

A No. I actually prepared the entire thing.
Q So you prepared the entirety of this?
A Yes.
Q Based on your review of PG&E's records and data?
A Yes.
Q And based on the NTSB report?
A I probably referred to the NTSB report somewhere.
MR. STODDARD: Okay. Thank you.
1-13.
MR. MOSHFEGH: Yes, 13.
MR. STODDARD: I'm going to introduce and mark Exhibit 1-13.
(Deposition Exhibit 1-13 was marked for identification and is attached hereto.)
BY MR. STODDARD:
Q Do you recognize this document, Ms. Felts?
A Yes.
Q What is it?
A This is the testimony I filed on behalf of UCAN in the SCG and SDG&E's Line 1600 Replacement case.
Q And if you'll turn to the Table of Contents,

which is on page 2, this provides kind of -- the Table of Contents for your testimony which includes prudent management of gas applied for safe operations demands, prudent engineering and various other subject matter areas that you cover in your subsequent testimony, correct?

MR. GRUEN: I'm just going to note an objection for the record.

To the extent this goes to the substance of the testimony, and it sounds like these questions are beginning to touch on substance, noting the objection at the outset that these are questions regarding a currently open proceeding to which SoCalGas and SDG&E are a party before the Commission.

And so the objection is that the -- any information that is elicited from Ms. Felts on this point, that it would be inappropriate to include that information in the record of that proceeding. And our understanding is that the information elicited is only for purposes for the notice of deposition in the Aliso Canyon proceeding.

And I would further notice that Ms. Felts -- that the attorney who is responsible representing UCAN, which -- and this testimony was prepared for UCAN -- UCAN's attorney is not present at the

deposition today.

MR. STODDARD: Your objection is noted again.

Q Ms. Felts, did you prepare this testimony?

A Yes.

Q Who was your point of contact at UCAN?

A Don --

I forget his last name.

Q Did anybody at UCAN hand you a draft of this testimony when you agreed to be their consultant and ask you to sponsor this?

A No.

MR. STODDARD: Thank you.

I'm going to introduce Exhibit 1-14.

(Deposition Exhibit 1-14 was marked for identification and is attached hereto.)

BY MR. STODDARD:

Q Ms. Felts, do you recognize this document?

A Yes.

Q It's an email from Darryl Gruen to Margaret Felts sent on Sunday, November 17, 2019, copied on Karen Shea with the subject line "Re: Status of testimony Attorney Work Product - Confidential."

Was it your understanding that your work was protected by attorney-client privilege or attorney

work product privilege?

MR. GRUEN: I'm going to just note an objection that that doesn't characterize the complete document in that there is indeed a response from Darryl Gruen to Margaret Felts, but that the remainder of that email is, in fact, an email from Margaret Felts dated November 17, 2019 at 9:25 p.m.

MR. STODDARD: Okay.

Q Again, just to confirm, however, it's two emails; the top email is from Darryl Gruen sent on November 17th to you with a cc on Karen Shea. And the subject line is "Re: Status of Testimony Attorney Work Product - Confidential."

A Yes.

Q "Yes."

Was it your understanding that your work was protected by privilege during this period?

A No. I was advised early on when I -- when I received the contract that my communications would probably not be confidential and could be disclosed.

Q Did you put that subject line in there?

A I don't know if I put it on there or if Darryl put it on there.

Q Okay. Who advised you regarding your statement a moment ago that whatever you did in this

proceeding was likely not privileged and therefore could be disclosed?

A Darryl Gruen.

Q In your email below which was sent on November 17, 2019 at 9:25, you wrote "Over the weekend, I read all 1597 pages of the Well File provided by PG&E to SED."

I assume in that instance you meant SoCalGas?

A Right. On the brain.

Q "I did this because I figured it would be the best representation of the condition of SoCalGas's files," correct?

A Yes.

Q And then you state "The file actually included records for Wells SS-25, SS-25A and SS-25B," correct?

A Yes.

Q Did you access this file through the Diamond database we were discussing earlier?

A Yes.

Q So you were, in fact, reviewing an electronic production of records from SoCalGas's well file provided in response to a data request, not a physical well file, correct?

A Correct.
Q And you reviewed all 1,597 pages in the weekend as well as the data responses we discussed earlier and the Blade report prior to your submission of your testimony on November 22nd?
A Yes.
Q Did you also look at the data responses, the responses to Data Request 16, that same weekend?
A Yes.
Q Did you look at the underlying records produced in response to Data Request 16, a document production?
A I had a hard copy, I think, of the whole response. But I haven't verified that against the electronic response.
Q Do you recall receiving a privilege log in connection with the Data Request 16 response?
MR. GRUEN: I'm going to --
Just a clarification. If this is asking about testimony, if that's where this is going, if the witness could be referred to testimony, the testimony where the questions are going to be directed, I'll just note that.
MR. STODDARD: I'll refer to the email.
Q The last sentence of the email states

"I also looked at the responses to Data Request 16. These are records related to the well-kill efforts, so post October 2015."

And in connection with that, I am wondering what you reviewed and what you had related to Data Request 16, including --

Well, my last question, which is do you recall receiving a privilege log related to Data Request 16 and did you review it at that time?

A I don't really remember that there was a privilege log, but it could be bound in the front of that document.

So what I received was a bound document that was about this thick that was all DR 16. And it was Bates paged through it. I just don't -- I wouldn't spend any time looking at a privilege log if there was one at the front of it. It could have been there.

And the document contained a lot of copies of emails, a lot of duplicates of emails, and Boots & Coots daily records, not particularly well organized, and some -- I think some communications from Halliburton, maybe some technical records from them, like a proposal or something.

Q Okay. Do you recall there being

supplemental responses to Data Request 16 included in the material you reviewed?

A I don't think anything was labeled that way. I think it was just the actual documents that were bound in that volume.

Q Okay. In response to my question regarding whether you reviewed a privilege log associated with SED 16, you stated that "I just don't" -- "I wouldn't spend any time looking at a privilege log if there was one at the front of it."

Since then, have you reviewed a privilege log associated with SED 16?

A I may have looked at it in -- on -- in the database. Have not really given it any thought.

Q Okay. Have you reviewed any other version of the well file aside from the version that you describe in this email?

A I think I've seen at least two other versions in the response sets.

Q In SED's Diamond database?

A Yes.

Q Have you ever reviewed the well files in person?

A No.

Q Have you ever reviewed Blade's copy of the

well file?

A Not yet.

Q Is it your understanding that SED is in possession of Blade's version of the well file?

A I believe they have it. I haven't seen it yet.

MR. STODDARD: I'm going to note for purposes of the record that SED produced this document to us, but we didn't get a separate production of the initial email.

MR. GRUEN: I'm sorry, I can't --

MR. STODDARD: We got the response.

MR. GRUEN: I'm not clear when you say "this document," I'm not clear what --

MR. STODDARD: Referencing Exhibit 1-14.

MR. GRUEN: Okay.

MR. STODDARD: We received --

You produced this document to us, but if you'll see, as you pointed out, this is two separate emails.

MR. GRUEN: Right.

MR. STODDARD: And the bottom email, which includes -- which is the email from Margaret to SED, we don't have an independent version of that; so we aren't able to tell --

One of the reasons I asked about who added the "subject" line is we can't tell who made that designation based on this document and whether it was included with hers, because hers doesn't include the data at the top, including the subject line or any other data.

MR. GRUEN: Okay.

So for the record, the document does note "On November 17, 2019 at 9:25 p.m. Margaret Felts," and it has her email address, "wrote:" And then it provides the text that was being referred to and asked about.

MR. STODDARD: That's correct.

MR. GRUEN: I'm noting that just for the record.

And I think you're asking for us to produce that, just for the record.

MR. STODDARD: Yes.

MR. GRUEN: I think you're asking us to produce that email, the original email; am I tracking correctly?

MR. STODDARD: That's correct.

MR. GRUEN: Okay. We can do that.

Just for the record as well -- strike that.

We'll go ahead with that. That's fine. Thank you.

MR. STODDARD: All right. I'd like to mark Exhibit 1-15.

(Deposition Exhibit 1-15 was marked for identification and is attached hereto.)

BY MR. STODDARD:

Q Ms. Felts, do you recognize this document?

A Yes.

Q And this is an email from you to Mr. Gruen dated November 18th. It's Monday, the day after the email that was marked Exhibit 1-14. And the subject line is "Confidential Attorney Work Product."

Do you see that?

A Yes.

Q Does this --

Did you add the "Confidential Attorney Work Product" subject line in this email?

A I could have added it, or I could have just replied to another email and added the text below. Sometimes I do that. I just pick out the latest email that Darryl sent and just reply, and use the same heading --

Q So you might --

A -- and send it.

Q So you might have deleted the other email in

this document?
A Yes.
Q Did you collect this document and provide this to Darryl for purposes of production to SoCalGas?
A I think Darryl probably sent it from his database, his email. I mean, produced it to you.
Q Okay. So do you commonly delete emails when you're replying in chains? Is that a typical practice or occasional?
A If I'm just looking for the latest email address for a person, that's what I do, I just pick one off of the most recent email and reply to it.
Q So in other words, if his email to you was on a different issue, you might --
A Yes.
Q -- delete that but use it for purposes of responding to him --
A Yes, that's correct.
Q -- or sending --
Ms. Felts, do you see where it says "Attachments: 2019 Draft Testimony"?
Do you see that?
A Yes.
Q You were sending Darryl a draft of your

testimony, correct?

A Yes.

Q Do you recall if this was the first draft that you sent him?

A I expect this was probably the first draft, and it was a draft of the part of the testimony related to records or recordkeeping.

MR. STODDARD: Okay. We're going to introduce Exhibit 1-16.

(Deposition Exhibit 1-16 was marked for identification and is attached hereto.)

BY MR. STODDARD:

Q Do you recognize this document, Ms. Felts?

A Yes.

Q Is this the document that you previously referenced as your draft testimony regarding recordkeeping issues?

A I expect that's --

This is it, yes.

Q And when you prepared this testimony you had reviewed the version of the well file in the Diamond database?

A Yes.

Q Which again was an electronic document

production, correct?
A Yes.
MR. STODDARD: Thank you.
We're going to introduce Exhibit 1-17.
(Deposition Exhibit 1-17 was
marked for identification and is
attached hereto.)
BY MR. STODDARD:
Q Do you recognize this document?
A Yes.
Q It's an email from Darryl Gruen sent on November 19th to you with copies on Amy Yip-Kikugawa, Nick Sher, and Karen Shea, correct?
A Yes.
Q And this was sent a day after you sent him your initial draft; is that correct?
A Yes.
Q And it included the subject line, "Attorney-client privilege confidential," with the proceeding number and SED Aliso testimony; is that correct?
A Yes.
Q Do you believe that this was a response to your email or one that originated from Darryl?
A I think it probably originated from Darryl.
Q And it identifies an attachment.

The file name is the proceeding number "SED Aliso Testimony.docx," correct?

A Yes.

Q And the subject line, and the contents says there is testimony attached?

A Yes.

MR. STODDARD: We're going to introduce Exhibit 1-18.

(Deposition Exhibit 1-18 was marked for identification and is attached hereto.)

BY MR. STODDARD:

Q Do you recognize this document, Ms. Felts?

A Yes.

Q What is it?

A It looks like the draft testimony that Darryl sent me.

Q And to confirm, you did not write this testimony, correct?

A Let's see, it looks like this version does not include the part of the testimony that I wrote, which was the records section; so that's correct.

Q And the records section that you prepared would eventually be inserted at the end, is that correct, toward the end?

A I think it's before Section C.
Q Was this your first time --
MR. GRUEN: Just a clarification, to the extent that we're starting to creep into the actual questions about the testimony itself, so I just ask --
I'd reiterate just to the extent that the questions go there, if she could be directed to the part of the testimony where the questions are being asked.
MR. STODDARD: Understood.
THE WITNESS: Let's look at this.
Okay. So looking at Exhibit 1-7, it was inserted as Section 3 at the end of the testimony.
MR. STODDARD: Thank you.
Q Was this the first time you saw SED's testimony?
A Yes.
MR. GRUEN: And just clarification, when you say "was this the first time," what time?
MR. STODDARD: The date that she received this email, which was as established in Exhibit 1-17, Tuesday, November 9, 2019.
THE WITNESS: November 19th.
MR. STODDARD: November 19, 2019.

THE WITNESS: Okay.
BY MR. STODDARD:
Q And that day was the first day that you saw at 5:15 p.m. SED's draft testimony?
A Yes.
Q Do you know whether they were preparing it immediately prior to sending it to you, or whether it had been in existence for a while?
A I don't know.
Q And do you know who authored it?
A No.
Q What was your initial reaction?
A Well, it's not the type of report that I would write, but it was drawn strictly from the Blade report, and so I felt like --
I think it adequately represented what the Commission was -- or what SED was looking at for violations.
Q Why was it not the kind of report that you would write?
A Oh, I might have had done more research in the data and been able to add a little bit more depth to some of the discussion.
Q So it was a little bit thin?
A Yes.

Q Did you read it in its entirety when you received it?

A Yes.

Q Aside from your concerns about the lack of support, do you recall whether you agreed with all of the assertions?

A I had some concerns about some of them, one of them being the --

I think there is a statement that was carried over from Blade that said that there were no indications of a leak on -- ever on SS-25, and my review of the records in the well file suggested that there had been indications of leaks on the shoe on that well. And then I was -- I thought I had that turned off.

There was another area that I wasn't --

Oh, I wasn't real sure about issues related to bottom hole pressure, and so I went back and reviewed that more carefully in the Blade report and agreed with that. I think those were the main areas that I went back and looked at.

I felt like I had not read all of the supplemental reports for the Blade report at that time, but I did look at the areas -- the supplemental reports that supported the areas that I wanted to

check on. And I did feel like Blade was very thorough in their investigation and felt like I could support the conclusions that were pulled over into this testimony.

Q Did you review all of the supplemental Blade reports --

Have you reviewed all of the supplemental Blade reports now?

A There is the last volume having to do with casings, whether it's some technical sessions of that that I haven't read yet, or actually I skimmed them, but I feel like I should go back and read them a little more closely.

Q When did you complete your first pass on the supplemental reports?

A Mid-January.

Q I'm going to direct you to page 36 of Exhibit 1-18. And you see there is a comment there from Darryl, and it's on the sentence that reads "External well-control specialists provide necessary experience and expertise; however, underground storage operators should also have personnel with the necessary skills to monitor and manage external specialists, a core skill for gas storage operator."

Do you see that?
A Yes.
Q And then the comment --
Mr. Gruen states "Margaret, do you have the expertise to say something along the lines of 'underground storage operators including SoCalGas should have personnel with the skills to do XYZ, even if they rely on third party well-control specialists such as Halliburton to do ABC. And multiple kill attempts demonstrate..?'"
Do you see that?
A Yes.
Q Did you discuss that comment with Mr. Gruen?
A I don't remember it, but I probably did.
Q Did you understand Darryl to be asking you to expand upon the highlighted sentence and provide further detail?
A No.
Q What did you understand Darryl to be asking?
A If I had the expertise to support a statement that he had written there or something like it.
Q Do you?
A As a petroleum engineer, I think I could say that SoCalGas should have somebody with that type of

experience, petroleum engineering, to oversee their subcontractors or their contractors.

Q And what type of experience is that?

A Some sort of reservoir engineering.

Q So --

A Or drilling or both.

Q So if they have --

If SoCalGas has somebody who is a reservoir engineer, a drilling engineer, then that would be sufficient?

A Yes. Yes, I think they do.

MR. STODDARD: All right. Thank you.

Let's see if I can get it right this time.

I'm going to introduce Exhibit 1-19.

(Deposition Exhibit 1-19 was marked for identification and is attached hereto.)

BY MR. STODDARD:

Q Ms. Felts, do you recognize this document?

A Yes.

Q This is an email from Darryl Gruen to you on Wednesday, November 20th, 2019; so a day after he had transmitted the prior draft that we just discussed, and it is transmitting -- and it includes another attachment of -- with the same file name -- no, not

quite the same file name, strike that.

It includes an attachment entitled proceeding number "SED Aliso Testimony" with the date; is that correct?

A Yes.

Q And the content of the email reads "Aliso testimony attached. Darryl."

I'm going to introduce Exhibit 1-20.

(Deposition Exhibit 1-20 was marked for identification and is attached hereto.)

BY MR. STODDARD:

Q Ms. Felts, do you recognize this document?

A Yes.

Q This is a revised draft that had been sent by Darryl Gruen on November 20th of the SED portion of the testimony. Please turn to page 37.

A Okay.

Q You'll note that the comment --

So it's slightly formatted differently because of a change in font size and some other formatting changes. But if you look up at the second sentence on the top of the page, that same sentence, "External well-control specialists provide," is there without the comment.

A Oh, yes.

MR. GRUEN: I'm sorry, I'm not tracking.

Is there a comment that is there? My copy, I don't see one.

MR. STODDARD: Sure.

Maybe it would be easier to compare with Exhibit 1-18, and reference, again, on Exhibit 1-18 page --

MR. GRUEN: Oh, I see.

MR. STODDARD: -- 36.

My point is this is the same sentence even though the pagination is different, the comment is gone.

Q Does this --

Do you recall now or does this suggest that you and Darryl had a conversation in the interim regarding his question about your expertise?

A All right. Let me look up -- it looks like the same statement.

Q Okay. Thank you.

Do you know why Mr. Gruen sent this version less than a day later after sending the initial draft?

A This draft has a recordkeeping section in it.

MR. GRUEN: I'm going to just note an objection that that --

Well, I'll strike the objection.

Go ahead.

BY MR. STODDARD:

Q Ms. Felts, can you direct me to the portion of the testimony that has the recordkeeping section in it?

A Okay. Well, you're right. It only has a heading for it on page 68.

Q Did you write that heading or did -- or did it appear in this draft or the prior draft?

A I expect someone else probably wrote it or maybe pulled it off of a draft I sent.

MR. STODDARD: Okay. Moving on.

Introducing Exhibit 1-21.

(Deposition Exhibit 1-21 was marked for identification and is attached hereto.)

BY MR. STODDARD:

Q Ms. Felts, do you recognize this document?

A Yes.

Q This is an email from you to Darryl Gruen, no one is copied, and it was sent on Wednesday, November 20, 2019 and the subject line is "Edits to

Testimony." And you see in your response to Darryl where you state "Darryl, I can't get the tracking to work. It's possible it is showing on your computer, but I'm hesitant to put the work into it is doesn't show."

Would I be correct that that is supposed to read "but I'm hesitant to put the work into it if it doesn't show"?

A Yes.

Q The next sentence says "So I'm going to finish my testimony, and you can go ahead and use the SED testimony as is. I don't think I can sponsor it as written."

Do you see that?

A Yes.

Q Were you referring to the draft that Darryl sent the day before that we were just looking at, Exhibit 1-20?

A I don't know if I'm referring to that one or the one prior that you had provided. Things were going back and forth pretty quick.

And I know that I was having a problem doing the tracking on my computer, my PC, but I got that resolved eventually, and I believe I had some concerns that we may have just walked through over

the phone and resolved.

Q And do you recall what your concerns were?

A I think -- I think my main concern may have been the issue with the statements in the testimony that Well SS-25 had never exhibited a leak.

Q So over that single issue you were indicating in this email that you weren't going to sponsor it as written and suggesting that Darryl go ahead and use the SED testimony as is?

A It's possible. I'm usually pretty picky about those things, and that was a fairly inaccurate statement.

Q Were there discussions about what SED would do if you didn't sponsor the testimony?

A Yes.

Q And what was discussed?

A I -- I don't remember exactly, but I believe there was discussion of releasing it without a -- someone supporting it.

Q Releasing it without someone's name on it?

A Yes.

Q Was there any discussion of alternative witnesses?

A No.

Q So after you received this email, as far as

you recall, you think you spoke with Darryl on the phone?

A Well, to correct you, I sent this email. I didn't receive it.

Q I'm sorry, thank you for the correction.

A And I believe we probably discussed it over the phone.

MR. STODDARD: I'll introduce Exhibit 1-22.

(Deposition Exhibit 1-22 was marked for identification and is attached hereto.)

BY MR. STODDARD:

Q This is an email from --

Do you recognize this document?

A I don't really recall it, but it appears I wrote it.

Q It's from you to Darryl Gruen dated Wednesday, November 20, 2019, 7:39 p.m., and the subject line is "SED Testimony Cleaned and marked up versions."

Do you see that?

A Yes.

Q And it includes two attachments. One, it appears to be a clean version, and one that says "With Original Footnotes."

Do you see that?
A Yes.
Q You said "Still have to merge mine into this one."
And you are referring there to the documents -- the document testimony that you drafted?
A The records section.
Q "The records section"?
A Yes.
Q And this one you're referring to the testimony that was prepared by Mr. Gruen?
MR. GRUEN: I'm sorry. Objection to the characterization of the testimony calling testimony as "prepared by Mr. Gruen."
That assumes facts not in evidence, and it's a mischaracterization of Ms. Felts' testimony.
MR. STODDARD: Restating.
Q You were merging the section you prepared on records, you were going to merge that one into the version prepared by SED?
A Well, I don't know who prepared it, but it was provided to me by Darryl Gruen.
Q And the email reads "The Clean version has all changed except accepted footnote numbers adjusted. The other version shows all comments,

edits and retains all original footnotes. Margaret," correct?

A Yes.

MR. STODDARD: We might need to take a break for a moment.

No, we don't.

MR. GRUEN: Jack, we can continue this.

Potentially maybe this might be -- or assume might be a good time for a --

MR. STODDARD: Let's just take a quick break.

MR. GRUEN: Do you want to do that?

MR. STODDARD: Yeah, we've been going for another hour or so.

THE VIDEOGRAPHER: Just a moment, please.

We are off the record at 2:30 p.m.

(Off the record.)

THE VIDEOGRAPHER: We are back on the record at 2:47 p.m.

MR. STODDARD: Okay. Picking up where we left off.

Just to circle back, we had just discussed Exhibit 1-22, which to recap included two attachments, which I'm now going to introduce.

The first we'll mark as Exhibit 1-23.

(Deposition Exhibit 1-23 was

marked for identification and is
attached hereto.)
BY MR. STODDARD:
Q Do you recognize this document?
A Yes.
Q This is a first attachment to the email marked as Exhibit 1-22, and this is the clean version of SED's revised draft testimony which you revised, correct?
A Yes.
MR. STODDARD: Introduce Exhibit 1-24.
(Deposition Exhibit 1-24 was
marked for identification and is
attached hereto.)
BY MR. STODDARD:
Q Do you recognize this document, Ms. Felts?
A Yes.
Q And is this the redline version of the testimony that you revised combining SED's draft with your draft and which was --
I'm sorry.
A Go ahead.
Q -- which was attached to the email now marked as Exhibit 1-22.
Strike that. Correction.

This is your redline of SED's portion of the testimony. It does not include the records section, but this is the redlined version of what was attached to the email marked as Exhibit 1-22?

A Yes.

Q Thank you.

I'd like to note for purposes of the record that this document was missing from SED's initial document production, and we had to specifically request it and received it only two days prior to the deposition.

Turning to page 1 of the document, page 1 of the revised draft testimony, which is actually five pages into the document after the Table of Contents.

Do you see the redline through in the introduction where it states "Drawing on the Blade report and information obtained in its own investigation, this testimony identifies numerous safety (and health) violations of PUC Section 451 related to the uncontrolled release of hydrocarbon gas or methane for 111 days from Southern California Gas Company's (SoCalGas) Aliso Canyon Well SS-25 (SS-25 incident) including many different causes identified in the Blade Report from which the SS-25 incident resulted"?

Do you see that?
A Yes.
Q And that you struck the language "including many different causes identified in the Blade report from which the SS-25 resulted," is that correct?
A Yes.
Q Why did you strike that language?
A Probably because I thought it was redundant.
Q Okay. Please turn to page 11.
Do you see at the top where you deleted the discussion of groundwater as a source of corrosion?
A Yes.
Q And down at the bottom of the page 11 where there is a sentence regarding groundwater and microbes, "a form of Archaea caused the corrosion"?
A Yes.
Q And then below that is another sentence regarding MIC as the mechanism of corrosion; do you see that?
A Yes.
Q And that those sentences are all deleted in your redline; is that correct?
A Yes.
Q And why did you delete those sentences related to microbial -- Blade's findings of microbial

corrosion?

A Well, at the time I felt like the information that was drawn from the -- it was drawn primarily from the main report, and I had not read the details of their analysis, their lab analysis that showed how they came to that conclusion. And so I just wasn't real solid on supporting those statements at that time; so I deleted them.

Since then, I've looked at all of those reports and read the underlying investigation data, and I could have supported it had I had the time to look at those; so I think it was sound science.

Q Okay. Will you be amending your opening testimony to add those findings back in?

MR. GRUEN: I'm going to object to that in that it calls for attorney work product and attorney-client privilege.

That's a deliberation that is still being considered by SED.

BY MR. STODDARD:

Q Ms. Felts, these portions of the testimony that you -- of the draft testimony that you deleted related to microbial corrosion, did you put them back into the testimony that was served, do you recall?

A I don't remember.

Q Referring back to Exhibit 1-7. Please take a moment to review and just confirm whether you added any of that language back in.

MR. GRUEN: Just so I'm clear, the question is to compare page 11 of Exhibit 1-24 with comparable page on Exhibit 1-7?

Am I tracking correctly?

MR. STODDARD: I'm asking more generally whether --

I'm giving her time to flip through the relevant sections of the document to identify whether she understands -- or whether she added this language back into the document, not particularly page 11 of the document.

MR. GRUEN: I follow. Okay.

THE WITNESS: It doesn't look like I added it back in.

BY MR. STODDARD:

Q But now since the opening testimony, you've reviewed the relevant sections of the Blade report, and you're more comfortable with their conclusions on that issue; is that correct?

A Yes.

Q So would it be fair to say that at the time that you served your opening testimony, you hadn't

considered the entirety of the Blade report?

A Some of the technical supplements to the Blade report were -- I had only glossed over, and so I felt like I really needed to go back and look at that in detail.

Q I'm going to direct you to page 42 of Exhibit 1-24.

A Okay.

Q Same question here, do you see where it says "Some of the 7-inch casing connections were seeping gas at the outside of the casing and then the carbon dioxide in the gas was likely a nutrient for the methanogens," and you deleted this language, correct?

A Yes.

Q And separate from the reference of methanogens, did you also doubt Blade's conclusions regarding the 7-inch casing connections?

MR. GRUEN: I'm going to object to the characterization of her testimony as doubting Blade's conclusions.

The objection is that it's a mischaracterization of her testimony thus far.

MR. STODDARD: All right, I'll restate it.

Q Ms. Felts, did you have similar concerns related to those you had with respect to the section

on MIC related to Blade's conclusions regarding the 7-inch casing connections?

MR. GRUEN: Same objection.

I think for clarification, she --

Well, I'll just note the same objection. It's concerns with the conclusions is a misstatement of testimony.

BY MR. STODDARD:

Q Ms. Felts, why did you strike that language that I referred to?

A Okay. So the statement is that there was seeping gas from a 7-inch casing which then fed or served as a nutrient to the microbial community that was causing the problem, so -- or causing the corrosion.

The main report lacked substantive support for that. And so it was necessary to go back and understand the tests that Blade ran on the 7-inch casing joints that showed or proved that there was leakage.

And so I needed to completely understand that part of the investigation to support that statement, and I -- had I really felt well about that, I would have also felt good about the seeping gas serving as a nutrient; so I deleted both sections

just because I hadn't gotten to a sound understanding of what they had done that caused them to make that statement in the main report.

Q And now you feel comfortable having reviewed that section of the report that Blade's conclusions with respect to microbially influenced corrosion are well supported?

A I think they did a pretty good job of the review and the science.

MR. GRUEN: I'm sorry, she wasn't finished with her answer.

THE WITNESS: That's okay.

BY MR. STODDARD:

Q And that the --

And their conclusion that there may have been Archaea microbes?

A I really don't have an alternate opinion other than what they concluded on that. And they base that on their scientific research and knowledge; so I think it's probably a good conclusion.

There may be something else out there, but I'm not aware of it.

Q And you have faith in Blade's scientific process and conclusions?

A I do. I think they did a good job.

Q But you didn't speak with anybody at Blade or interview anyone at Blade, correct?
A No, I didn't.
Q Did you evaluate the credentials of the Blade personnel?
A I believe I did look at their credentials, and also I think I looked up some information about them online just to see what type of work they've done before, and it seemed like they had a fairly good history in the industry.
Q Did you review the description of Blade's sampling and microbial analysis protocols?
A Yes.
Q And you felt that those were sufficient and complied with standard procedure?
A I think so, based on my experience.
Q I'm going to direct to you page 20 of Exhibit 1-24.
A Okay.
Q Do you see the sentence in the second full paragraph where it says "The SS-25 temperature and noise logs had never shown an anomaly related to casing integrity"?
A Yes.
Q And is that your comment in the margin?

A Yes.
Q And the comment reads "I know this is a quote. However, you should know that temp and noise surveys on SS-25 showed one or more leaks from 1978 to 2012. But, these leaks were not shallow."
What was the basis for that comment?
A I had looked at the well file, and I was just reporting that there was something in the well file that showed that there were leaks.
Q And what was that something?
A Temperature surveys, primarily. I believe there is one or more noise surveys.
Q And you think --
You believe that both the temperature surveys and the noise logs showed leaks?
A There is no question that the temperature logs show leaks. The noise surveys seemed like they were inconclusive. Sometimes I think because they ran the noise logs under the wrong circumstances.
Q And this was based on your review of the electronically produced logs that were in SED's Diamond database?
A Yes.
Q And you disagreed with Blade on this point, correct?

A Yes.
Q Is it your understanding that Blade's investigation was conducted over a period of several years?
A Well, from 2015 to at least 2018.
Q And earlier you stated that you believed Blade did a very thorough job, correct?
A I think they did. I -- my -- I think --
And this is just my probably assumption is that they didn't have access to the same information I've had access to when they came to this conclusion. I don't know that for a fact. I just know they received some really late data from SoCalGas. And it's possible that they were basing their conclusions on DOGGR records, where they would not have seen this.
Q And, again, you did not review the records that Blade Collected or any of the productions and data responses that SoCalGas sent to Blade in connection with preparing your testimony, correct?
A That is correct.
Q Or in connection with this comment, correct?
A That's correct.
Q If Blade hadn't reviewed these records -- actually, strike that.

And these records, you found them in the well file that was available in the Diamond database, which included records related to SS-25, correct?

A Yes.

Q If Blade didn't review the records related to SS-25, do you believe that their investigation would be thorough?

A For what --

For the primary work that Blade was doing, I don't know if they needed the historical records. They needed the construction records; so they had what they needed from the Department of Oil and Gas records that were on file there.

This was just one area where for some reason they either were told or came to the conclusion that there was no -- had not been any prior leaks on that well. I don't --

There is no question in my mind that if they had looked at the records that I looked at, the temperature surveys, they wouldn't have said that; so I have to conclude they didn't see them.

Q And do you believe that the alleged fact of historic leaks is relevant to the alleged 451 violations in your testimony?

MR. GRUEN: I'm going to object that that calls

for legal conclusion.

I just am noting an objection for the record.

And more broadly just to the extent that there are questions that go to any violations in testimony that asks for a legal basis for violations, we're going to restate an objection. And we'll note discussion in the pre-hearing conference related to that.

But I wanted to note that objection for the record.

Having said that, she can answer the question.

THE WITNESS: Can you ask the question again?

BY MR. STODDARD:

Q Is your opinion regarding the presence of a historic leak dating back to 1978 at SS-25 relevant in your view to your alleged -- to the alleged violations of 451 in your testimony?

Let me restate that.

A Okay.

Q If there are no leak --

If there was no historic leak at SS-25, is that a mitigating factor in your view related to SoCalGas's O&M practices at SS-25?

A The reason for my concern in making the statement that there was no leak was just that it was an inaccurate fact in a report, and I'm a records person, so I like things to be accurate and based on records. And certainly since my testimony -- the written part of my testimony that went into this document had to do with recordkeeping, I was particularly sensitive to the fact that everything in this testimony should be accurate as it was recorded in records.

And in this particular case, the record file for SS-25 included a number of annual surveys that documented a leak at the bottom shoe of the well. And because this particular file excluded any analysis or memos about that ongoing leak, whereas other well files including 25A and 25B had that kind of -- those kind of notes in them, I felt like it was something that I should call attention to, at least among the PUC people.

It has, I think, little bearing on the -- the violations that were cited one way or the other.

Q Okay. You stated that you are a records person so you like to have things be accurate and based on records, correct?

A I like them to -- statements to accurately

reflect what is in the record.

Q And this statement, based on your review of records, you believed Blade was incorrect?

A Blade may have been correct on what they were looking at. It was incorrect based on the documents review I had done.

Q Did you endeavor to look at the underlying records on Blade's other findings in the Blade report?

A I think I considered everything that they made available. And certainly looked at -- looked at the testimony in light of the records that I had available to me, and this was the one that I had the most concern with.

Q Did you communicate to SED which records you thought would be necessary for purposes of being able to support the testimony, or was it simply accepting what SED gave you and limiting your review to that?

A I'm not sure I understand your question.

Q Let me take a specific example.

So you indicated, and correct me if I'm misstating you, but you indicated that you disagreed with Blade's conclusions regarding the -- their interpretation of the temperature logs or their statement regarding the historical noise logs at

SS-25. You disagreed with that based on your review of the records, correct?

A What I disagreed with was the statement the SS-25 temperature and noise logs had never shown an anomaly relating to casing integrity. That's the statement I disagree with.

Q And that was based on your review of records?

A Yes, which show anomalies relating to casing integrity; so the statement can't be correct. Now, it may not --

You said that I disagreed with Blade's interpretation of logs. I don't know that they had access to those logs.

Q Did that raise any doubts in your mind as to Blade's other findings or conclusions?

A No.

Q So taking an example on page 17 of Exhibit 1-24 regarding failure to implement a risk assessment program, it cites to the Blade report in the first sentence, "Corrosion was not detected on SS-25 because the 7-inch casing wall thickness on the SS-25 had never been inspected."

Did you verify that through inspection of records?

A There is no evidence of an inspection of the wall thickness in the SS-25 well file.

Q And with respect to Blade's identification of a failure to implement a risk management plan as a root cause, did you confirm their conclusion that it hadn't been implemented based on a review of records?

A Yes, there is no risk assessment program or any documentation of a risk assessment in the well file.

Q Did you look outside of the well file?

A We asked many -- in many different ways for risk assessments and have consistently been told that there are no records.

Q That's based on your review of which documents?

A Well --

Q You said "we asked."

Who are you referring to?

A I'm referring to SED in data requests.

Q And those are data requests that were made available to you through the Diamond database?

A I wrote some of those discovery questions, and the answers came back that there were none.

Q Turning back to the temperature logs.

What experience do you have with respect to

interpretation of temperature logs?

A I studied that in petroleum engineering, and other than that, none --

Nothing specific. It's not a fine science.

Q And could a temperature log be indicative --

Could a temperature log anomaly be indicative of something other than a leak?

A Well, I think maybe, but these -- these temperature logs in the SS-25 well file actually have notes on them that say "potential leak." It's pretty obvious, and the temperature survey, the numeric temperature survey printout shows a reduction in temperature, so --

And if you compare that well log or that well file and the temperature surveys in that well file to other well files at Aliso, you will see that a similar thing was happening at other wells, and there was responsiveness to it by SoCalGas.

For some reason not so on -- or it doesn't appear so in the well file for SS-25. It's not a one-time thing in this well. It was happening across Aliso.

Q You mentioned the temperature reading spike that would occur and indicate an anomaly --

A Actually a drop in temperature.

Q Right.
A Yes.
Q So the drop in the temperature that you can see on the temperature log --
A Yes.
Q -- correct, could that possibly be due to the presence of water behind the casing?
A Not likely at the shoe where this leak was occurring. It's very a common leak in these wells.
Q And do you recall what depth that was?
A Probably very close to the bottom, so it would be the bottom shoe.
So this well was about, I don't remember exactly, 8300 feet deep; so it would have been around that depth.
Q Okay. Direct you to page 28. Again, here same issue, statement regarding annual temperature and noise logs, and you deleted the clause that says "no anomalies were found," and included a comment that says "Wrong, we could replace the Blade footnote with SS-25 well file."
A Okay.
Q Again, you're disagreeing with Blade here.
Do you recall any other instances where you disagreed with Blade?

MR. GRUEN: I'm going to object. Asked and answered.

THE WITNESS: Well --

MR. GRUEN: She can answer the question, but it's been asked and answered before.

THE WITNESS: This is --

I mean, there might be other places in the testimony where I struck the thing having to do with the temperature survey, but I think that was -- that and the MIC issue were the two things.

BY MR. STODDARD:

Q I'm going to direct you to page 30, the sentence says "Kill operations where a fluid being pumped into a well while the gas is escaping at a high rate requires a detailed transient model to define the operational parameters."

And I apologize, I was reading that before you got to the page.

But do you see where I'm talking, it's highlighted?

A Uh-huh.

Q And you flagged it and said "Let's talk about this."

Do you know why you wanted to talk about it?

A I don't really remember. Something

triggered that thought. Possibly I might have wanted to talk about the bottom hole pressure.

Q What about bottom hole pressure?

A Just that that seemed to be -- let me back up.

Using the lower-than-actual bottom hole pressure might have been a problem for the kill operations. They couldn't wait -- or were not waiting there, the fluid they're pumping down the well to a heavy enough weight to overcome the reservoir pressure.

Q Again, Ms. Felts, you don't have any experience with well-control operations, correct?

A Well, not directly, but as an engineer I studied it, and it's not a -- it's not a fine science. It's just an engineering calculation.

Q An engineer with a suspended license, correct?

A I don't have a suspended license. Why do you say that?

Q I thought you indicated at the beginning of our deposition that your license was on hold.

A No, I have a general -- I have a general contracting license that's on hold, just has nothing to do with this.

Q So your engineering license is active?
A I don't have an engineering license --
Q Do you have any certification --
A -- in California.
Q In other jurisdictions?
A No.
Q But you have a general contractors license?
A Yes, that was --
Q And that's what has been put on hold?
A Well, I put it on hold. You can --
If you don't want to pay $500 a year for your general contracting license, you can pay $200 a year and then reactivate it when you have a contract; so that's what I did. It's still valid.
Q And is that related to work that you do on any energy facility context?
A Well, it's a general contracting license, and I used it for years doing drilling, monitoring wells and cleaning up hazardous waste sites. It has a HAZ rating with it.
Q Okay. Direct you to page 33. See the section --
I'm sorry, I'll let you get there.
A Okay.
Q Second full paragraph, second half, "It is

probable that continued pumping from the surface might have kept up with the fluid loss, but surface plumbing failures prevented the well from being kept filled."

Why did you delete that sentence?

A I think I deleted it because I didn't think it was necessary for the testimony.

Q Same question for the next sentence, "The use of fresh water and clear brine contributed to the attempt's failure because of fluid loss into the formation and loss of hydrostatic pressure, which allowed the well to flow after the kill attempt."

A Same point.

Q Refer you to page 46 and 47. There is a discussion here related to the chemical nature of groundwater.

A Yes.

Q And the sentence starts "Factors that control the chemical nature of the groundwater are mineralogy, transmissibility, and topography."

Why did you delete this paragraph?

A Here again, I thought this was too much detail and not contributing to the testimony.

Q Did you disagree with the substance?

A No.

Q Factual accuracy?
A No. I just thought it was drawing way too much detail into the testimony.
MR. STODDARD: I'm going to introduce Exhibit 1-25.
(Deposition Exhibit 1-25 was marked for identification and is attached hereto.)
BY MR. STODDARD:
Q Do you recognize this email, Ms. Felts?
A Looks like it's an email from Darryl to me. I don't remember it.
Q It's the day before your testimony was served; is that correct?
A Yes.
Q And the email reads "Margaret, I'll call you about this shortly. Darryl." And it has an attachment titled "Recommended Fixes."
A Okay.
MR. STODDARD: I'm going to mark Exhibit 1-26.
(Deposition Exhibit 1-26 was marked for identification and is attached hereto.)
BY MR. STODDARD:
Q Do you recognize this document, Ms. Felts?

A Not really.
Q This was the attachment to Exhibit 1-25, which was Darryl's email to you with the attachment "Recommended Fixes," and Darryl said he was going to call you about it.
Do you recall Darryl calling you about it?
A No, but ask questions if you want.
Q Okay. Do you know if this document was incorporated into your testimony?
A I don't recognize it. Do you know where it is in the testimony?
Q I'll refer you to Exhibit 1-7.
A I have that here.
Q Turn to page 77. 76.
A Okay.
Q Does this refresh your recollection?
A Okay. I see where it is. I understand what it is. Okay.
Q Okay. I take it you didn't write this section, correct?
A No.
Q And it doesn't sound like you reviewed this section either, correct?
A I'm sure I read it because I read the whole testimony before it went out.

Q But you don't recall discussing it with Mr. Gruen?

A Well, we probably discussed it because we went over all of this before it went out. But looks a little --

Let me see.

Okay. We probably just walked through it toward the end.

Q Okay. So you don't recall feeling uncomfortable about the fact that Mr. Gruen sent you a new section of your testimony that you were agreeing to sponsor the day before you were due to serve it?

A Well, I think this was something that was probably already being discussed, and it just got finalized here.

Q Discussed with you?

A Yeah.

Q But you don't recall?

A Well, I don't recall this format of it. I guess this is how it looked when it was printed out from the email. This looks more familiar, what is in the testimony. It's just a formatting thing I see.

Q Looking at the one in the final testimony --

A Okay.

Q -- starting at page 26.
A Okay.
Q Do you recall --
A 76 or 26?
Q I'm sorry, 76. Thank you.
A Okay. Okay.
Q Do you recall discussing "Solution 1, Production casing should be cemented to the surface" --
A Yes.
Q -- with Mr. Gruen?
A Yes. This is --
That was a common finding, yes.
Q And do you recall doing any research or investigation on this recommendation?
A Well, I'm sure it came right out of the Blade report.
Q So for purposes of this, you are relying on the Blade report and you're satisfied with their findings on this issue?
A For purposes of almost the whole report, I was relying on Blade, and I felt pretty comfortable with it. We just went over the areas that I wasn't comfortable with.
MR. STODDARD: Okay. Thank you.

I'm going to introduce Exhibit 1-27.
(Deposition Exhibit 1-27 was marked for identification and is attached hereto.)
BY MR. STODDARD:
Q Do you recognize this document, Ms. Felts?
A Yes.
Q And this is an email from Darryl to you --
A Yes.
Q -- marked "Attorney-client privilege," attaching a revised or a -- I'm sorry, with an attachment titled "Felts.2019 Draft Testimony 112119," correct?
A Yes.
MR. STODDARD: Introduce Exhibit 1-28.
(Deposition Exhibit 1-28 was marked for identification and is attached hereto.)
BY MR. STODDARD:
Q Do you recognize this document, Ms. Felts?
A This looks like the recordkeeping section.
Q Is this Darryl's revisions to the initial draft recordkeeping section that you sent him?
MR. GRUEN: Objection. Calls for speculation, assumes facts not in evidence.

BY MR. STODDARD:

Q Is this a revised version of the draft that you initially sent to Darryl?

A It looks like there is a couple of comments on it, all for me to confirm footnotes.

Q Do you see the comment on page -- the pages are not numbered, the second-to-last page of the document?

A Yes.

Q Is that a comment from Darryl?

A In the red -- little red box?

Q Yes.

A Yes.

It says "Margaret to confirm accuracy of footnote."

Is that the one you're looking at?

Q Yes.

And you believe that's a comment from Darryl?

A I think so. It says "GD1." That's his initials and number 1.

Q Referring back to Exhibit 1-16 --

A 1-16.

Q -- for comparison purposes --

A 1-16. I don't seem to have it. There

should be one in this stack.

THE VIDEOGRAPHER: Counsel, while she is looking, may I have a moment to change my disks?

MR. STODDARD: Yes.

THE WITNESS: I got it.

THE VIDEOGRAPHER: This is the end of disk number three, Volume Number 1, in the deposition of Margaret Felts on February 5th of the year 2020.

We are off the record at 3:39 p.m.

(Off the record.)

THE VIDEOGRAPHER: This is the beginning of disk number four, Volume number 1, of the deposition of Margaret Felts on February 5th of the year 2020.

We are on the record at 3:44 p.m.

MR. STODDARD: Thank you.

Q Referring back to where we were, we were comparing documents 1-16 with 1-28.

And for sake of context, 1-28 is a later version of the same document as 1-16, except that 1-28 was sent from Mr. Gruen to Ms. Felts the day before her testimony was filed -- the day before her testimony was served.

I'm going to direct you to page 2 of both documents at the bottom.

A Okay.

Q Do you see the sentence starting "The significance"?
A Yes.
Q "The significance of these files" --
In the older document it states "The significance of these files is that they contain records not included in the SS-25 Well File but relevant to the operation, maintenance and closure of Well SS-25 because these wells share similar design," and it goes on.
In the more recent version that Darryl sent to you on the 21st, it states "The significance of these files is they contain record types such as Interoffice Memos, handwritten field notes, analyses, and reports that are not included."
That's a change relative to your original draft; would you agree?
A Yes.
Q Did you make that change or did Darryl make that change?
A I think I made --
MR. GRUEN: Objection. Calls for speculation as to the actions of Darryl Gruen.
BY MR. STODDARD:
Q Did you make that change?

A I made the change orally to Darryl.
Q So you had a phone call to discuss the prior draft?
A Yes.
Q Do you believe that all changes in this document were made by you pursuant to that phone call?
A Well, there is one on the front page that I know was, and that was where we deleted a paragraph I wrote about 451 and slightly modified the first paragraph, I think, so --
And in this one I know, because Darryl wouldn't know about interoffice memos, handwritten field notes and analyses and reports. I had to have said that.
Q Why wouldn't Darryl know about that?
A Because he hasn't read that well file, I don't think.
Q And how about looking at the footnotes on page 2?
A Footnotes on page 2?
Q Yeah.
MR. GRUEN: Of which exhibit?
MR. STODDARD: I'm sorry, of Exhibit 1-28.
THE WITNESS: Okay.

BY MR. STODDARD:

Q They did not appear in Exhibit 1-16, correct?

A Okay. That's true, but I would have -- I would have told him what the footnotes had to be. He wouldn't have known.

Q Okay. And do you believe that's likely the case?

Do you recall the conversation you had with Darryl about these changes?

A Yeah.

Q Do you think all of the changes were probably made pursuant to --

A Yes.

Q -- your discussion?

A Uh-huh.

Q I'm going to direct you to the first page of Exhibit 1-28.

A Yes.

Q The second footnote related to Public Resources Code Sections 3106, 3180, 3181, 3220 and 3403.5.

Did Darryl also make that change at your direction?

A No. I would guess he probably actually put

the code sections in there because that's related to, see footnote 2, so we probably looked at it while we were on the phone, and he probably put it in.

Q But you're not sure?

A I'd have to look up the code and tell you for sure. But if it's -- if it's DOGGR codes, then I put it in. If it's PUC codes, he put it in.

Q Okay. So it might be helpful for purposes of the record actually then to introduce them so you can confirm based on the subject matter.

A Okay. That would be helpful.

MR. STODDARD: We'll mark this as Exhibit 1-29.

(Deposition Exhibit 1-29 was marked for identification and is attached hereto.)

MR. STODDARD: I apologize the first page is Section 3008, which you don't cite to; its just definitional. It's just definitional the first page, that's 3008.

THE WITNESS: Right.

BY MR. STODDARD:

Q That is not something that you cite. But if you turn to page 2, it's Section 3106, take a moment to review it.

MR. GRUEN: I'm sorry, just for the record, it

appears as if there are multiple page 2's in the document; so just to --

Could we clarify which page 2 is being referred to for the record?

MR. STODDARD: Yeah.

So to clarify what has been marked as Exhibit 1-29 is California Public Resources Code Sections 3008, 3106, 3180, 3181, 3315 and 3320, 3316.2 and 3403.5, and I -- they are stapled together.

And I was directing the witness to the second page of the packet, which is Section 3106.

MR. GRUEN: Understood. Thank you.

THE WITNESS: Okay.

BY MR. STODDARD:

Q So you've reviewed the document.

Having done so, did you add these citations?

A I would have added them.

MR. STODDARD: Okay. Thank you.

We can take a break if it's okay with you.

MR. GRUEN: Okay.

THE VIDEOGRAPHER: We are off the record at 3:52 p.m.

(Off the record.)

THE VIDEOGRAPHER: We are back on the record at

4:25 p.m.

BY MR. STODDARD:

Q Ms. Felts, I'm going to reference with the next questions Exhibit 1-7 --

A I got it.

Q -- which is your opening testimony that was served.

A Okay.

Q Turning to pages 3 through 6 of this document.

A 3 through 6?

Okay.

Q Do you see violations starting at number 95 and going through 320?

These are violations that relate to SoCalGas's assertions of attorney-client or attorney work product privilege; is that correct?

A Lack of cooperation, is that what we're talking about? Am I looking at the wrong thing?

Q Yes, 95 to 320, "Lack of Cooperation."

A 320, yes.

Q And for each of these --

If you want to take a moment to review, you can, but for each of these, it relates to SoCalGas's privilege claims?

A Okay.
Q And that's the majority of the violations that are asserted in your testimony, do you agree?
A Numerically, yes.
Is that what you're talking about, "the majority"?
Q Yeah, the majority.
A Yeah, okay.
Q Yeah. All right. Now, turning to Section 2, C.2 that is referenced in association with these violations.
A And page?
Q I'll have that for you in a second. 52.
A 2, I see 2 on page 52.
Q Yeah.
And earlier you stated that you did not draft this section, correct?
A Yes.
Q And that is everything related to the privilege issues, correct?
A Yes.
Q But you are sponsoring this portion of testimony, correct?
A Yes, I agreed to sponsor the entire testimony.

Q How did you get comfortable to sponsor this section?

A Well, I guess I went over these particular violations with -- with Darryl and discussed them with him.

Q When did you do that?

A It would have been prior to the testimony going out.

Q And you feel that you have a good understanding of the underlying facts related to this issue?

A Well, I think I have a pretty good understanding of what was happening.

Q Did you review any underlying documents associated with these violations?

A I reviewed the documents that were attached, the exhibits.

Q Do you recall any specifically?

A Not without looking at them. I should remember them. I think I just looked at them yesterday.

Q But earlier it does not include the privilege log associated with SED 16, correct?

A There was a point in time when I looked at the privilege log. I just can't really answer any

questions about it unless you show it to me.

Q Do you recall reviewing any of the documents that SoCalGas withdrew its privilege claims -- for which -- let me restate that.

Do you recall reviewing any of the documents that are the basis for the alleged violations?

A These are the documents.

Q Related to the privilege issues?

A The documents that you eventually produced --

Q Correct.

A -- I'm pretty sure I saw them. I don't --

It seems like I remember emails, but I'm not --

I mean, I can't tell you the content of them just as I sit here today.

Q Do you recall reviewing any correspondence or letters between SoCalGas and SED related to meet-and-confer meetings --

A No.

Q -- on the privilege issue?

A Not specifically.

Q Do you recall reviewing any data responses related to the privilege issues from SoCalGas?

A I think I probably did. If you want to ask

specific questions, you're probably going to have to show me the documents.

Q And do you feel as though you understand SoCalGas's position with respect to its initial privilege assertions relative to the privilege -- relative to the documents that are at issue in the privilege log?

MR. GRUEN: Jack, if I may, I think there is a --

I'm going to object to the question as vague in that if there is a particular area in the testimony that you want to direct -- or documents, the witness has called for documents that you can use to ask questions.

But the vagueness in this question is the actual position.

Without identifying the piece of testimony or the document where it's stated, it's going to be hard for the witness to answer a question like that.

MR. STODDARD: Understood.

I'm trying to understand the witness's process with respect to sponsoring this testimony; so I'll restate the question.

Q Just as a matter of fact, did you consider SoCalGas's position with respect to the privilege

issue in evaluating the testimony that you were provided by Mr. Gruen?

A Are you asking me if I understood why SoCalGas was claiming privilege?

Q Yes.

A I think I -- I think I understood what SoCalGas said was their purpose in claiming privilege. That's probably not the same as saying that I understood it. I --

MR. STODDARD: Offer this as exhibit.

(Deposition Exhibit 1-30 was marked for identification and is attached hereto.)

MR. STODDARD: Take a moment to review that document.

MR. GRUEN: Just, Jack, just for clarification, you want her to review the entirety of this document?

MR. STODDARD: No. I want her to review it to the extent she is --

If you need additional time, just ask for it. If I ask a question, we can see --

THE WITNESS: Why don't you ask a question and see how far we can go with it?

BY MR. STODDARD:

Q Okay. Do you recognize this document?

A I've seen it.
Q Did you review it in connection with preparation of your testimony?
A No, I did not have it until after then.
Q Okay. Thank you.
Ms. Felts, I'm going to direct you to page 62 of Exhibit 1-7.
A Okay.
Q Middle of the page, do you see where it starts "By SED's count, approximately 18 additional documents were released"?
A Yes.
Q And then it says "Each of the 95 pages that SoCalGas did not release on the grounds of attorney-client or attorney work product privilege is a Section 451 violation because it delayed SED's ability to get this information as part of its pre-formal investigation."
Do you see that?
A Yes.
Q Are you aware of any specific information in the 95 pages that you believe was important to SED's investigation?
MR. GRUEN: Objection. Mischaracterizes the use of the term "investigation" as -- in the past tense

mischaracterizes it.

The investigation is ongoing.

THE WITNESS: The way I could answer that is that apparently this, in part, relates to the DR 16 response. And if portions of the DR 16 response were not available, it would be difficult to nail down some of these violations. But since I don't know which pages specifically out of that response were withheld, I can't answer.

BY MR. STODDARD:

Q Well, I'm asking, Ms. Felts, what this information in your testimony is referencing because there is no citation, so I'm not sure.

But it says "Each of the 95 pages that SoCalGas did not release on the grounds of attorney-client or attorney work product privilege is a Section 451 violation because it delayed SED's ability to get this information as part of its pre-formal investigation," and I'm asking what that information was in your view?

A I think this information refers to the 95 pages that SoCalGas did not release.

Q Do the contents of those 95 pages matter in your view as to whether or not it's a Section 451 violation?

A I don't think it's the contents that is the issue here. I think it's the release of the documents that were requested. So it goes to the investigation overall.

If you don't know what is in the records, you have to assume that it's possibly not safe -- a condition or relevant to a condition that is not safe; so it prohibits the complete investigation by not being able to look at the records.

Q That's not what this sentence says though.

It says that SoCalGas did not -- that "Each of the 95 pages that SoCalGas did not release on the grounds of attorney-client or work product privilege is a violation because it delayed SED's ability to get this information as part of its pre-formal investigation" seems to be suggesting that there was information in there which was material to the investigation that SED was prevented from getting.

Would you agree?

A And I think that's the assumption that they made when they didn't get it.

So it's made prior to receiving the 95 pages. You can't make a judgment on the content of something that you haven't received yet; so it's the delay that is the problem.

Q Are you --

Is it the case, then, that you believe that SED did not receive these pages at the time that these violations were asserted?

A I'm actually not sure when the pages were turned over.

Q Okay. Above that, do you see the sentence that says "By SED's count, approximately 18 additional documents were released"?

A Yes.

Q And there are violations both for those 18 documents and the 95 pages; is that correct?

A I think that's correct.

Q Can you explain why in one instance the violations are linked to documents and in the other it's pages?

A That's --

I don't know. That was a choice of wording, I suppose. Maybe somebody counted up the pages in the 95 number.

Without having the 18 documents in front of me, I can't tell you whether that's 18 individual documents, therefore 18 pages, or 18 multiple-page documents.

Q In general, discovery requests are for

documents, not for pages, would you agree?
A Yes.
Q Do you think it would be more reasonable to assert violations based on documents that were withheld versus documents that happen to have multiple pages that were withheld?
A I don't really have any history on that as far as the way violations are counted.
Q But you are sponsoring this testimony, correct?
A Yes.
Q So why in your view should violations be calculated on the basis of individual pages for multipage documents?
MR. GRUEN: I'm going to object.
This line is calling for legal conclusion as to how violations are counted. This is a legal question that is appropriate for briefing, not questioning of the witness.
She can answer if she wants to, but this is -- in SED's view this is a waste of time.
THE WITNESS: Without looking at both sets, the 18 and the 95, I don't know why it was chosen to call one documents and one pages, but I would expect that the 95 pages is probably 95 documents; so other than

that, I think -- I think it should be consistent. It's probably my fault for not checking it.

MR. STODDARD: Thank you.

Q In the set that you did review, do you recall noticing any duplicate documents? Again, this is related to the --

A Privilege.

Q -- the privilege, the 95 or the 18.

A I don't recall offhand, but duplicates are very common in SoCalGas responses. Certainly in DR 16 there were duplicates upon duplicates of emails.

Q And if there were duplicates of documents in this data set, would that change your assessment as to whether or not it should be a violation?

A If the duplicates should be a violation?

Q If the withholding of the duplicate for basis of privilege should have been a violation of 451 and Rule 1.1?

A Well, I think you're making the assumption, again, that the -- I could assess the delay of producing things I don't know what they are, you know, ahead of time because I wouldn't have known that there were duplicates in that set.

All I know from a privilege log is that

you're claiming privilege for X number of documents, and you probably had a page count on them in the log, but --

So you claim the privilege -- or SoCalGas did then. That took a certain amount of time to get the documents, and that's the delay, and that's the basis of the assessed penalty.

Q Okay. Turning back to the beginning of Exhibit 1-7 --

Actually, set that aside for a second. I'm going to ask some other questions without referencing a document.

Ms. Felts, what experience do you have with -- what prior experience do you have with root cause analysis investigations?

A I've only reviewed root cause analysis. Mostly related to pipeline cases.

Q How many root cause analyses have you reviewed?

A I don't have an exact count, but I'd say probably at least over 50.

Q And you said mostly related to pipeline cases; is that correct?

A Yes.

Q Do you recall any that were related to gas

storage fields?
A No.
Q Are you familiar with the phrase "technical root cause analysis" as opposed to root cause analysis?
A I wouldn't know the difference if there is -- if there is a difference.
Q So no?
A Not in the field as it would apply to this type of incident.
Q And you say you've reviewed over 50 root cause analyses; is that correct?
A Yes.
Q Have you ever prepared a root cause analysis?
A No.
Q Or been on a team that was preparing a root cause analysis?
A No.
Q Have you overseen preparation of a root cause analysis?
A It's possible that at the refinery and at Celanese I was involved in overseeing root cause analysis on some incidents.
Q Prior to this matter, what was the most

recent root cause analysis that you can recall reviewing or being involved in?

A In the San Bruno case I reviewed all of the historical analyses that were provided, and there was a whole archive of them at PG&E.

Q Was that root cause analysis prepared by the NTSB; is that correct?

A No. These would have been either in-house by PG&E or by external third-party contractors and -- for PG&E.

Q And in your experience how do those prior root cause analyses compare to the Blade report in terms of volume and length?

A It was quite a variation depending on the incident and probably the significance of the outcome of the incident. But I would say overall the Blade analysis was far more extensive and detailed, but the engineering or technical analysis of the pipe itself is very similar.

Q So the metallurgical piece?

A Yes.

Q And in reviews of other root cause analyses that you've done, have you looked only at the report, or do you also look at underlying data, information, that was collected by the investigator in the course

of preparing a root cause analysis?

A I've generally had access to all of the data and underlying records, assuming they're available. Sometimes if you're going really back in history, all you get is the report. But most of a metallurgical analysis would have lab reports attached to them and photographs and basic information that the report relied on.

Q And in this instance have you been offered access to review that information for the Blade report?

A I would say that a lot of it is in the supplemental technical reports that were provided in the additional volumes.

Q But beyond the supplemental reports, the actual data they collected or, you know, images that they didn't include in the report ---

A I haven't reviewed anything outside of what they provided.

Q What is your understanding of the purpose of a root cause analysis investigation?

A Generally?

Q Generally.

A To determine what the cause of an incident was or a failure, pipeline failure, a well failure.

Sometimes it's an operational issue that caused a problem; so it's generally to determine what the cause is of an incident.

Q So that you can prevent similar incidents from occurring in the future; would you agree?

A Well, that's a good start. If you can figure out what caused it, then you can figure out how to prevent it in the future.

Q But would you agree that that's one of the purposes of a root cause analysis is to identify the causes in order to prevent similar -- in order to prevent reoccurrence of similar events?

A It's one.

Q And would you agree that a root cause analysis investigator should include all potential causes?

A Well, I mean, if they did a really good root cause analysis, they should be able to determine what the cause was, not a range of causes.

Q In conducting their investigation though, when they're considering potential causes for purposes of scoping their investigation, would you agree that they should include all potential causes, or do you think they should circumscribe it?

A I would think a good engineering review

would include a range of possibilities at the front end, and then you would start eliminating them pretty fast because you would want to focus in on where the data is leading.

Q And that the root cause analysis investigator should follow the data toward what they identify as a root cause?

A I think so.

Q Regardless of whether or not that root cause relates to something that is required by law?

A I don't think required by law has much to do with a root cause analysis.

Q Regulation?

A Same thing. I mean, whether it's required or -- a required activity or not, the cause is still going to be technical, unless you're looking at an operational issue, if somebody did or did not do what they were required to do and caused an accident, say.

Root cause analysis could be performed on a lot of different kinds of incidents, like car accidents, you know, and purposes can range too. A lot of them are called for by insurance companies. They just want to know where to assign liability. They don't care whether it gets fixed.

Q Referring back to Exhibit 1-7 --

A Okay.
Q -- direct you to pages 7, 7 to 9.
MR. GRUEN: I'm sorry, 7 and 9?
MR. STODDARD: 7 through 9.
MR. GRUEN: 7 through 9.
BY MR. STODDARD:
Q Starting with page 7. This identifies "A root cause for the SS-25 incident was the lack of detailed follow-up investigation, failure analyses, or RCA of casing leaks, parted casings, or other failure events in the field in the past."
Do you see that?
A Yes.
Q "There have been over 60 casing leaks at Aliso Canyon before the SS-25 incident, but no failure investigations were ever conducted."
A Yes.
Q Do you contend that a root cause analysis should have been performed for all 60 casing leaks?
A Well, I would say that it would not be possible to do a root cause analysis in the manner that Blade did because you would have to take the well out of service and pull all of the casing; so that wouldn't be practical.
On the other hand, I think there were things

that SoCalGas could have done to determine the cause of failures, not just that a failure occurred, which seems to be what was typically happening. They could have determined causes using available technologies, and they didn't --

As near as I know, as I can tell they did not, at least not until I saw some study in 2014 on I think it's Well FREW2 that actually went to determining the cause of the corrosion, but -- and maybe that one actually wouldn't be considered a root cause analysis. But certainly it was closer.

In most of the well files that I have looked at, I don't see any evidence of an effort to determine cause.

Q You mentioned tools that can be used while the well remains in service to determine cause?

A Yes.

Q Can you identify some of those tools?

A Oh, I think we did that in a data response. But there are tools that can be run into a well while it's killed temporarily in order to measure the thickness of the well casing or a tubing thickness. There are other kinds of logs that can be run that would give you a sense of erosion or conditions of the wells.

So I think you have to pick the right log technique and contractor and collect the data and see what you can find out about the well.

Q So had SoCalGas, after identifying a failure, run casing inspection logs, in your view that would have been sufficient for purposes of identifying cause in a failure investigation?

A No. I think once they had determined, say, that there was -- there were a number of failures, say, in the same area -- either depth of wells or across a geologic formation, like sand with water in it has corrosion in a number of wells exposed to that sand, maybe the casings are all, you know, not cemented. If there are similarities across the wells, then I think they should maybe take one of those wells out of service and do a more extensive study.

Q But the question related to a specific well failure in terms of what an investigation would be for a specific failure, so taking one in isolation.

MR. GRUEN: I note an objection for the record.

It is not Safety and Enforcement Division's role to identify the kinds of investigations that Southern California Gas Company should be doing on its own field. That is the role of the operator and

it's -- the --

This goes beyond -- generally speaking, this goes beyond the scope of the testimony to ask questions prompting your witness, Ms. Felts, to identify how SoCalGas should be investigating its field.

So she can answer the question, but we're noting the objection for the record and -- on this question and others to which SoCalGas asks how it should be investigating its fields, including leaks in this one.

MR. STODDARD: Noted.

Q So to repeat my question, for purposes of a specific casing leak --

So earlier you talked about kind of a more regional type of potential investigation. I'm focusing in on what would have been adequate investigation for a particular casing leak.

After a leak is identified or there is a condition or a failure, had SoCalGas run a casing inspection log after killing the well, would that have been sufficient for purposes of identifying the cause?

A Probably not. There is probably going to have to be some additional information, but I can't

tell you exactly what it would be. And I would guess that if it were my well, and I wanted to find out the cause, I would probably call Halliburton or one of their competitors and say "What is your latest technology? How can we figure out what the cause of this failure is?" And they would be happy to charge me a lot of money and come tell me how to do that.

Q But you wouldn't kill the well, cut the casing and do a full-blown RCA?

A Well, it depends. Because I think actually SoCalGas did kill wells and look at casing in some instances. I'm not sure that they generated any reports that said what caused the failure in the well.

But if you have a low-producing well, it's not useful in the management of the field anymore and it's in a location -- it failed and it's in a location where it would provide useful information, there might be a good reason to take it out of service completely and remove some casing to find out what caused the problem. Because it could provide vital information for the rest of your wells that are operating well right now but might not be later.

It's an engineering decision that would have to be made by SoCalGas's reservoir engineers.

Q But to restate the point that you made earlier, an RCA for each and every failure would not be practical, correct?

A An RCA, to the extent that Blade did this one for SS-25, is not practical. It's not field practical for an operating field.

Q Okay. Direct you to page 3, 4, 5 and 6. This is the "Table 1: Summary of Violations," and this is in Exhibit 1-7.

A Okay.

Q Do you see the columns in this table titled "Begin Date" and "End Date"?

A Yes.

Q Did you validate the begin date and end date for each of these categories of violation?

A No. I can tell you right off the bat that I just resist doing the violation calculation; so I usually say to the PUC "Unless you need my help figuring out a start and end date, go ahead and fill it in."

Q So then you don't ask factual questions to assess the reasonableness of the start dates and end dates?

A Well, I'll look at them. For instance, if I saw that a date was completely wrong based on the

data that I had reviewed, then I would say something.

Q Based on the data that you've reviewed.

But you wouldn't ask for information to support specifically the alleged begin date and end date -- and take, for example, Violation Number 84?

A Okay, let's look at 84.

Q Page 4.

A Okay. Okay. And so this one they --

I know they started the date at the date of the memo in 1988 that said, gee, we should look at these wells and assess them for corrosion because of exposure to groundwater; so that started it in 1988. And the end date was the date that the Well SS-25 blew.

Q And for purposes of Violation Number 76 --

A 76.

This would be a date that was established by someone at the PUC having to do with some finding about inability to collect recovery; so I'm not familiar with that, with that date. And the end date, again, is the date that the well blew.

So I'm guessing that someone needed money from the Commission to support a program and delayed some action for that period of time.

Q So you're guessing.

But you don't know the particular facts to support that begin date?

A I don't know the underlying purpose of selecting 12-31-2009.

MR. GRUEN: I'm going to just ask for purposes of this line to reference where in the testimony we're talking to.

There is a testimony section that we're in that this is just the table summarizing violations; so if there is a specific line of questioning about the actual testimony that this refers to, I ask that the witness be directed to that portion of testimony.

MR. STODDARD: You didn't include page numbers here; so the witness is free to reference whatever she needs to reference in this document.

She said she reviewed it in advance of today's deposition. This is --

THE WITNESS: It says II.B, II.C, if I can find it.

MR. STODDARD: Yeah.

THE WITNESS: Looks like it's page 17.

Okay. So this is based on a James Mansdorfer recommendation that they start a Storage Integrity Management Program, but apparently it didn't start -- maybe it didn't start at all, but was

recommended in 2009.

So the start date of the violation was 2009. I'm assuming they picked the last day of the year to start the violation.

BY MR. STODDARD:

Q And why is that your assumption?

A It would be the most conservative choice in 2009. Any other day within 2009 would result in a higher penalty.

Q And you don't know Mr. Mansdorfer, correct, you stated earlier?

A No.

Q And you haven't spoken to him, correct?

A No. I read his interview.

Q You read his EUO?

A Yes.

Q Did you review this --

Did you review the documents aside from --

This is his EUO transcript here that is cited.

Did you speak with anyone else about Mr. Mansdorfer's EUO transcript with respect to this issue aside from Mr. Gruen?

A No. I believe he produced some documents, or maybe SoCalGas produced some documents by him that

I reviewed.

Q That are related to this issue?

A Yes.

Q Turning back to page 3. Again, trying to understand the factual basis for begin date and end date.

Violation Number 3, which is referenced at Testimony Section Number II.B.1.a.

A This is probably about page 16, I would guess. Okay. Okay.

Q Did you find the relevant section?

A Yes.

THE VIDEOGRAPHER: You lost your microphone.

THE WITNESS: I lost it again?

Okay. Is that better?

Okay, number 3. This is --

It says "No investigation on one of four parted well casings."

I had it, I lost it. Okay.

Okay. The violation extends from the Blade report. This has to do with a well. The casing was parted or found to be parted in 1969.

You see the page is number 7?

BY MR. STODDARD:

Q And the basis for that start date?

A That's the date of the first -- the earliest well casing report of a failed well casing in the SoCalGas well records as it was reported to Blade.

So Blade had a history of well casing failures, and that was the earliest one that was reported. And so that date was 1969, not 12-31-1969, but, again, the conservative date would be the last day of that year.

Q Would it be relevant to your testimony on this violation if SoCalGas did not own or control the field at that time?

A I considered that. And it's relevant, but it's not -- not necessarily decisive because SoCalGas was in the process of acquiring -- acquiring the field before 1973, which I think was maybe the operational date. They probably had an application in to the PUC for money to renovate the field.

In order to estimate those costs, they would have to have information about the wells and what they would have to do to them; so I'm guessing -- and I'm only guessing because I don't have records yet, but I would say it's likely that SoCalGas was aware of this problem with this well.

Q So the start date of the violation dates to SoCalGas's knowledge of when the violation -- when

the failure occurred?

A That's how it was set out in this testimony.

Q If SoCalGas did not have control of the field at that time, would you agree that SoCalGas could not have completed a failure investigation on that well at that time?

A I don't know how much control they had over doing investigations into wells that they were about to purchase. I don't have enough knowledge to answer that one way or the other.

Q Assume for the sake of argument, hypothetically speaking, that SoCalGas didn't have control sufficient to conduct an investigation or direct any other operational actions at the field prior to acquisition, would that be relevant to your testimony on this violation?

A I think it might --

Yes, it would be relevant. It would also be relevant to know whether they requested any failure analysis from the prior owner Tidewater.

Q Isn't it likely, Ms. Felts, that SoCalGas didn't possess the well files as of 1969 if they didn't own or control the field?

MR. GRUEN: Objection. Calls for speculation.

She can answer if she knows.

THE WITNESS: They were in the process of acquiring this field for a number of years; so I would guess, again, that some documents had to have exchanged hands, or there was some viewing of documents. I can't imagine SoCalGas bought all of these wells with no knowledge.

BY MR. STODDARD:

Q But to confirm a begin date for this violation is based on your assumption that SoCalGas would have had some form of access to both records and the ability to direct their predecessor in interest to conduct an investigation prior to acquisition?

A The begin date was originally just established on the fact that the parted casing on this well occurred in 1969; so you can argue it however you want to argue it.

Q Well, you said you considered the point that I'm asking --

A Yes.

Q -- which is SoCalGas's date of acquisition?

A And I explained that I think SoCalGas probably had access to information about this well, and may have been able to determine what the cause of this parted casing was.

Q But you don't know, correct?
A That's correct. I don't know anything that SoCalGas doesn't tell me.
Q And you're not aware of any records indicating that that's the case, correct?
A The -- the date, I believe came from Division of Oil and Gas records. But as far as a failure analysis, there is none in the record that I'm aware of.
Q My question was are you aware of any documents or other evidence that SoCalGas had the ability to perform a casing -- a failure investigation at that well prior to acquisition of the field?
A I don't currently have that information.
Q Okay. Thank you.
Referring back to pages 8 and 9 at the top of page 8, do you see there where it says --
And actually you have to turn back, I'm sorry, to the very end of page 7.
-- "Blade reviewed 124 gas storage wells and identified 63 casing leaks, 29 tight spots, 4 parted casings, and 3 other types of failures."
Do you see that?
A Yes.

Q And then your testimony discusses those.
And then in the bulleted section below it asserts specific violations "for failure to investigate the blowout from Frew-3 spanning from December 31, 1984" to October 23, 2015, the date of the incident.
And then a second violation for the failure to investigate the blowout at FF-34A, four violations spanning from 1969 to 1994 related to parted -- failure to investigate parted casings, and then 60 leaks -- or I'm sorry, 54 violations for failure to investigate an additional 54 leaks.
Do you see that?
A Yes.
Q You indicated earlier that prior to service of your testimony you reviewed well records related to SS-25, SS-25A and SS-25B, correct?
A Yes.
Q And in the course of that review, you found temperature logs based on which you disagreed with Blade's conclusion regarding a lack of anomalies in the temperature logs at SS-25; is that correct?
A Yes.
Q For these leaks that are listed here and for the alleged failure to investigate for each, how many

of these well files did you review?

A At the time I was relying entirely on Blade for the counts, and I -- I am not sure, but I believe Blade was relying on Division of Oil and Gas records.

Q And that's also what your belief was for purposes of the temperature log you disagreed with, correct?

Or, rather, their conclusions regarding the lack of anomalies in the temperature log, it was also your belief that they were relying on DOGGR records for that, correct?

A And did not have access to the well logs, yes.

Q Yeah.

So were you satisfied that if they were relying --

In your view or belief they were relying on DOGGR records for purposes of this analysis, what gave you confidence that this was accurate?

A Well, DOGGR records that they were reviewing were actually well histories that are reported by SoCalGas.

So if SoCalGas reported a leak, I'm guessing there was a leak. I don't think there would be any advantage for SoCalGas to report a leak on the well

history if there wasn't one.

So they were just counting up casing failures and leaks, and they were looking for cause -- a determination of the cause of those and not finding that.

Now, I don't know what other access -- without looking at what SoCalGas's responses were to Blade's data requests, I don't know what other information they rely on to do that. But I hope to find out. But I haven't seen it yet.

Q If they were relying on DOGGR records, given your experience or your views on the lack of information there related to the temperature log, isn't it possible that they were still miscounting the number of leaks here?

A I don't see any way they could be miscounting the leaks. Could be undercounting them.

Q That's miscounting, correct?

A Yes, but it would be to the advantage of SoCalGas if they undercounted.

Q Does the characterization of the type of leak matter for purposes of violations related to failure to investigate?

A A leak is a leak, so I would say no, although --

You could have, for instance, five holes in the same location, in a very small area in a pipe and call it one leak, whereas I think within the industry, a leak is just a failure of the casing.

So, you know, how you count the leak may determine on how detailed you get in terms of how many holes are in a piece of pipe.

Generally, I think SoCalGas would probably report just a failure. If they had a failure and they had to patch it, they wouldn't count the number of holes that were under the patch. It would be one leak.

Q What about leaks that aren't in the body of the casing, is that relevant in your view?

A Leaks, for instance?

Q For instance, a shoe leak.

A Well, a shoe leak is important because you lose gas through it.

So if you're in the business of storing gas for your own business or for someone else, you don't want to be losing it into a part of a reservoir where you can't get it back.

Q And what about leaks, "Leaks" that are the result of faulty -- something like a valve that may not be operating properly, would that in your view be

a leak, a mechanical piece of the well?

A What are you talking about, a release of the gas into the well or external to the well?

Q A leak that would show up on a temperature log.

A I don't know how that would show up on a temperature log.

Q All right. Let me ask it differently.

Are you aware of any instances where an operator might deliberately put holes in a tubular or casing?

A You would perforate a casing purposely, yes. That would be so you can either inject or extract the gas from that level of the reservoir.

Q Would it ever be done for purposes of cementing?

A Yes.

Q And are those holes on occasion plugged with cement?

A Sometimes.

Q And if one of those holes were to be leaking gas, in your view, is that a leak that requires investigation or simply repair?

A I would suppose if they understood exactly what was going on that they would just patch it, and

there would be no purpose to investigate it because the recurrence is not likely to occur unless, say, something was dissolving the cement.

Q I'm going to direct you to page 13 of your testimony.

A Okay.

Q You'll see here this relates to the heading "SoCalGas Did Not Implement a Risk Assessment Program Or Wellbore Integrity Management Plan on the Aliso Canyon Storage Facility Prior to October 23, 2015," and if you turn to page 16, which is the end of this section under this heading, it states "SoCalGas's failure to implement any form of risk assessment program or wellbore integrity management plan on the Aliso Canyon storage facility prior to October 23, 2015, and beginning 2009 and continuing through the date of the incident, constitutes a separate violation of Section 451 for each day it failed to implement the risk assessment program."

Do you see that?

A Yes.

Q And then I'm going to refer to the next two sections, section b) also relates to SoCalGas's failure to implement a risk assessment program or wellbore integrity management plan prior to the date

of the leak.

Do you see that?

A Yes.

Q And resulted in the failure to detect corrosion on the well at the 7-inch casing prior to October 23, 2015.

Prior to October 23, 2015 would include 2009, would it not?

A Yes.

Q Aren't these two violations really the same thing, which is SoCalGas's alleged failure to implement a risk assessment program or wellbore integrity management plan?

MR. GRUEN: Objection. Calls for legal conclusion.

MR. STODDARD: All right. I'll ask it in a different way.

Q The underlying conduct, which is a factual question, that serves as the basis for these violations is the same, is it not?

A Yes.

Q And that's also true for the next Section c) "SoCalGas Did Not Start a Storage Integrity Management Program in 2009, Even Though It Was Recommended by Its Storage Engineer Manager At

That Time Because They Could Not Yet Collect It in Rates," is that correct?

A The start date and underlying issue of storage, no storage integrity management program is the same.

Second half of it is different, and it has to do with a decision they made -- SoCalGas apparently made related to not being able to collect and rate the money to start the program. Slightly different in my mind.

Q But the underlying conduct related to the violation is the failure to initiate an integrity management program, correct?

A That's what it's linked to, yes.

Q Okay. Thank you.

And for all three of these sections on pages 13, Section a), 16 Section B), and 17 Section C) the basis for the statutory violation legally is Section 451, correct?

A Yes.

Q Ms. Felts, do you know which agencies are involved with regulation of gas storage operations in the state of California?

A Department of Oil and Gas would be the primary agency. I would expect the Energy Commission

might have some interest as a secondary.

The Public Utilities Commission, because they're operated by utilities, the Air Board probably has an interest because of air emissions, and the possibly local water boards because of potential water discharge from separators and that sort of thing on the surface. And probably also for groundwater contamination.

Q And at the federal level, are you aware?

A I would think that California would probably have most of the authority, although there might be some authority under PHMSA for some of the pipelines that are connected to the gas storage.

Q Are you aware of the memoranda of understanding related to the Aliso Canyon investigation between DOGGR and the CPUC?

A I have not seen it.

Q You have not seen it. Okay.

Which agency do you believe has primary jurisdiction over down hole gas storage and gas storage wells?

A Department of Oil and Gas.

Q I want to refer back to your testimony. This again is Exhibit 1-7 page 18. Paragraph -- or I'm sorry, header 3, "SoCalGas did not have a dual

mechanical barrier system in the wellbore of SS-25, instead leaving the 7-inch production casing as the primary barrier to the gas."

Do you see that?

A Yes.

Q Can you explain exactly what is meant by a "dual mechanical barrier" here?

A The idea would be to have it designed so that you have tubing going down the middle of it and then an external casing finished through your top casing so that your external casing is separate -- serves as a barrier. But in this case, because they were producing and injecting through both the casing and the tubing, then you lose the protection you don't have in, like, a second wall outside of your production casing.

So in this case Blade is saying that they didn't have that extra protection; so when the 7-inch casing failed, there was nothing outside of it to contain the gas. It was a true failure.

Q Are you familiar with the usage of dual mechanical barrier at other gas storage fields?

A I actually don't know what the -- I don't know what technology is used in the wells in other storage fields around the United States. I haven't

looked into that.

Q Okay.

A I'm assuming Blade knows.

Q I'm going to refer you now to page 19. And there is an embedded quote. And this discusses SSSVs.

Do you see that?

This -- I'm sorry, this is the embedded quote at the bottom of page 19. "Also as noted by SoCalGas's Storage Engineering Manager, James Mansdorfer."

A Okay.

Q And the discussion of subsurface safety valves goes on to page 20.

A Yes.

Q Can you explain how subsurface safety valves relate to the lack of a dual mechanical barrier?

A Apparently they did not at the time have SSV that would accommodate injection and production out of both tubing and the casing. Though they installed some, I think they installed three different ones in SS-25 very early on and ended up removing them or removing the guts of the valves because they couldn't get them to work.

And then in later -- I saw maybe this quote

is from that note -- memo from James Mansdorfer that he thought there was a new technology out there that they could probably install in some of the wells that would accommodate that sort of production and injection.

Q I don't believe that exactly answered my question.

I am wondering how SSSVs relate to the dual mechanical barrier issue or whether they do?

A I think I answered that. I don't know why --

Q Rather than I -- if you could restate your response. I'm not --

I can see the history that is accounted here, but operationally do they -- does inclusion of an SSSV provide a dual mechanical barrier?

A No.

Q Okay. If a field is converted to tubing flow only, those wells would have a dual mechanical barrier, correct?

A Yes.

Q Do you know what the diameter of -- the range of diameters for tubing is relative to a production casing in a gas storage operation roughly?

A Do you want a range of the size of tubing?

Q Let me restate the question.

Tubing is significantly narrower than casing, correct?

A In this case, it's 3-7/8 and the casing outside of it is 7-inch.

Q So converting a field like Aliso Canyon to tubing outflow only would have a significant impact on deliverability, correct?

A Not necessarily.

Q How so?

A I think it --

Because they can replace the tubing with a larger tubing. And the efficiency of a well depends on more things than just the size of the tubing; so it depends on the permeability of the reservoirs they're producing out of, how much gas they can pack in at what pressure and how fast that will flow back.

There could be other factors in the design of the well and the well head that would allow for a more efficient production; so I don't think you can just pin it on the size of the -- the initial size of the tubing.

Q "The initial size of the tubing."

So let me ask another question and see if this helps clarify it.

But taking an existing field with the parameters you noted as factors in deliverability, if you take an existing field, holding all of those parameters constant, and you put tubing into an -- existing wells that presently has 7-inch casing, would that reduce deliverability of that field?

A If I put a new tubing in it?

Q Uh-huh.

A At what size?

Q You indicated big tubing.

A Well, you can't go any bigger than the 7-inch casing. But I think that they have tubing that is in the 3- to 5-inch size. And, I mean, here again, you would have to ask a drilling company to spec that out for you to make sure that it would work.

Q So let's say 3-inch.

A Okay.

Q Would that reduce deliverability to the field?

A Not if you're going from a 2-7/8 to a 3-inch.

Q If you're putting -- I'm sorry, if you're putting new tubing into a field that presently doesn't operate as a tubing flow only field, so if

you're presently operating it as a dual flow gas storage field, and you convert it to tubing flow only and you're extracting it through a 3-inch tube, would that reduce deliverability to the field?

A If you hold everything constant, and all you're doing is you're going to produce out of the tubing and not out of the casing, then you're going to have a reduced flow.

Does that answer it?

Q Yes.

A You don't have to replace the tubing.

No matter what you do, if you're not producing out of the casing and you keep the casing the same size, you're still going to have reduced flow, and holding everything else constant, if you don't do anything else to improve efficiency.

Q Okay. Turning to page 23, middle of the third paragraph down where it states "It is not possible to determine what an inspection of the SS-25 casing would have shown in 1988, but it is possible that the corrosion was present and detectable, and steps could have been taken to avoid the leak in 2015."

Do you see that?

A Yes.

Q And the next sentence says "SoCalGas logged some of the 13 remaining wells starting in 2007, resulting in a gap from 1990 to 2007 when no inspection logs were run in the 20 wells, according to the available well records."

Do you see that?

A Yes.

Q And this relates to the 20 wells that were on the 1988 memo, correct?

A Yes.

Q Did you evaluate the logs of any of the 13 remaining wells that were logged starting in 2007 referenced in that second sentence?

A Not before this testimony was published.

Q Have you done so since?

A Some of them, yes.

Q And what did they show you?

A I think that's probably part of my future testimony, so --

MR. GRUEN: We'll note the objection for the record.

MR. STODDARD: And the objection is?

MR. GRUEN: The objection is that this is protected under attorney-client and attorney work product privilege to the extent that it covers work

that is going to be -- testimony that is going to be produced in the future. Excuse me.

BY MR. STODDARD:

Q Please turn to page 27, middle paragraph.

Do you see the sentence that says "Further, since no formal risk assessment was conducted regarding well integrity, wall thickness inspection was not identified as a monitoring technique"?

A Yes.

Q Do you contend that SoCalGas was unaware of casing inspection tools?

A No.

Q Can you explain your statement there what you meant by "was not identified"?

A I think this statement comes from Blade, and basically I -- what I think I am saying there is that since there wasn't a formal risk assessment conducted, it wasn't possible to -- to say that wall thickness inspection was performed.

So, in other words, if you had a risk assessment, a formal risk assessment, it would have the results of this monitoring technique. It would be pretty common in one of the first things you would do in a formal risk assessment. But without a risk assessment to look at, I can't conclude that the tool

was used.

Q And you say you think that's what you're saying, but this is based entirely on the Blade report, correct?

A Well, it came out of the Blade report, yes.

Q So this is what Blade is saying?

A Yes.

Q Turn to page 72, please.

A Okay.

Q Do you see where it states the "Well file for SS-25A contains information" --

In the second paragraph?

A Yes.

Q -- "that might have been useful to SoCalGas and its contractor in calculating the appropriate requirements to kill the well in October 2015 and thereafter."

A Yes.

Q What information were you referring to there?

A I believe it's attached as an exhibit. It was --

I'm just remembering that it's a Halliburton report on the reservoir characteristics that were logged by Halliburton. I'm not sure what the date

was. But it included permeability readings for the full depth of the well.

Q So maybe it would be helpful just to read the rest of the paragraph.

"For example, the Permeability of the Aliso reservoir is in a record in that file."

A Yes.

Q And can you explain how permeability was a factor for purposes of the well kill?

A When you look at the Blade model results, Blade had to assume a permeability. They didn't have the data; so the data was also not in the SS-25 well file, it was in SS-25A.

So if someone went to look for permeability, which would have been useful in their calculations or models, assuming that any of the contractors like Boots & Coots were actually doing calculations, say, on a calculator or computer that we don't know about, but let's say that they were, they would need that piece of data.

And so there is a statement in the Blade report that says if you change the permeability in the model that they were running, you got different results. And so I went looking for the permeability data to see if it was available to Boots & Coots.

And for SS-25, it was not in that file, but it was in the SS-25A file. And since they're right next to each other, it would have been relevant.

Q And you said that that document was not available to Blade, correct?

A Not available -- apparently not available. They --

Q To Blade?

A Yes.

Q Yeah.

Boots & Coots is the operator that performed the well kill, correct?

A Yes.

Q Earlier you indicated you don't have any -- any experience with well-control operations, correct?

A Not directly.

Q So then you're not aware of whether permeability of the reservoir is something that a well-control operator would typically consult or reference or consider?

A I just went by what was reported in the Blade report that they needed in order to do their calculations.

So this was part of their -- part of their calculations, and it was a factor that they didn't

have and had to make some assumptions about.

Q Okay. Let's move on to the next sentence in the SS-25A well file.

There is an example of a well kill that failed due to the use of an incorrect bottom hole pressure.

A Yes.

Q This is another record that you contend might have been useful to SoCalGas and its contractor in calculating the appropriate requirements to kill the well, correct?

A Yes.

Q Do you believe an incorrect bottom hole pressure here was the reason that the well-kill operation failed?

A Yes.

Q And what is your basis for that belief?

A Well, again, the models that Blade ran consistently showed that they weren't weighting the material properly. It wasn't heavy enough to overcome the reservoir pressure, and they actually recalculated based on old data that was provided or acquired from SoCalGas and came up with a higher bottom hole pressure, Blade did.

Q And you believe this is the case for kills 2

through 6?

A Yes.

Q The next sentence is "Other examples include the shallow leak on SS-25A and the formation of hydrates in an instance of leak repair, which may have been useful information."

Do you contend that Boots & Coots did not understand how to clear the hydrate that formed -- or according to Blade the hydrate that formed at SS-25A -- or, I'm sorry, at SS-25 during leak response?

A No.

Q Do you contend that Boots & Coots was unaware that there were hydrates in the well during the second well-kill attempt?

A At the time --

Q Let me restate that. I'm sorry.

Do you contend that Boots & Coots was unaware of the potential for hydrates after the first well-kill attempt?

A No. I think they were always aware of the potential.

Q How specifically would the document related to formation of hydrates in the instance of leak repair been useful to SoCalGas or Boots & Coots with

respect to the leak response?

A Well, without looking at the reference documents, I can't say specifically. But as I recall just sitting here, I believe there was a shallow leak that might have been informative as to the depth of the leak, and I don't remember the issue having to do with the hydrates just offhand.

Q And to reiterate, based on these, the footnote citations, this is based on your independent review of the well file and not the Blade report, correct?

A That's correct.

Q And Blade did not raise these concerns regarding these records in connection with the well kill, correct, to your knowledge?

A No. Let me correct that.

They raised the issue of not knowing the permeability because that was in their report.

Q Blade not knowing the permeability?

A Yes, and not having -- not having access to that data; so they made an assumption about what the permeability was. I'm not sure what that was based on. But they did provide additional calculations in their report with different permeabilities and said if it was this permeability, this would have

happened. So they were clearly considering a range.

Q But Blade did not raise the document-related issues related to the other items -- the other examples that you provide in this paragraph in connection with the well-kill operation, correct?

A It's not in their report.

(Discussion off the record.)

MR. STODDARD: I guess can we go off the record for a moment, please.

THE VIDEOGRAPHER: Just a moment, please.

We are off the record at 5:59 p.m.

MR. STODDARD: This is the end of disk number four, Volume Number 1, of the deposition of Margaret Felts on February 5th of the year 2020.

(Off the record.)

THE VIDEOGRAPHER: This is the beginning of disk number five, Volume Number 1, of the deposition of Margaret Felts on February 5th of the year 2020.

We are on the record at 6:22 p.m.

BY MR. STODDARD:

Q Ms. Felts, picking back up again with Exhibit 1-7, I'm going to direct you to page 44 and 45.

The heading for this section is titled, starting with lower case b) "SoCalGas Did Not Assess

the Relationship Between Groundwater In and Around the SS-25 Well Site, and The Surface Casing Corrosion of That Well."

Do you see that?

A Yes.

Q And on page 45 it states "SoCalGas's failure to assess the relationship between groundwater in and around the SS-25 wellsite and the surface casing corrosion of that well on SS-25 constitute a violation of Section 451."

Do you see that?

A Yes.

Q What is your understanding of practices at other gas storage fields relating to the assessment of the relationship between groundwater and well casings?

A Anybody who drills a well has to at least have a preliminary idea of where the groundwater is; so that starts because you case down to the bottom of the groundwater, fresh groundwater.

Q And by "case down," you mean set your surface casing?

A Yes.

And so after that I would not know exactly what the practices are at other gas facilities.

Q Okay. Thank you.

In terms of how to assess the relationship, do you know how Blade assessed it for purposes of their RCA investigation?

A I think they drilled a couple of wells.

Q And do you believe that that would be required in the proximity of each well at Aliso Canyon to understand the relationship between groundwater and the wells?

MR. GRUEN: Again, I'm going to note the objection that this is calling for SED to recommend investigations to SoCalGas as to how to investigate its field, which is beyond the scope of SED's purview.

But she can answer.

MR. STODDARD: Actually, let me restate the question.

Q Ms. Felts, what is your understanding regarding how to assess the relationship of groundwater in a storage field relative to the casings in a gas well?

A There are options. You might do them all. One is the simple option of being very familiar with the geology after drilling wells and/or looking at the geology reports from the drilling and then

understanding where sands, sand lenses outcrop and water would fall on the sand at the outcrop and run down the -- that part, that part of the strata. And so where it would impact each well, you would know approximately the thickness of that sand, and that would be the exposure to that amount of water; so that's a geologic approach that requires no drilling.

In addition to -- or alternatively, you could set monitoring wells in those sands that are cased to and then open to those sands so that you could monitor the depth of groundwater at any point in the area. You would have to --

You wouldn't set a well next to every well, but you would set a monitoring well in an appropriate place where your geologist thinks that there might be some variation in the depth of water in that lens, that sand lens.

There could be other ways to do some sort of monitoring that might hit in between those two. You might have historical water production when you were drilling a well like a newer well and be able to report that, and then connect that to a sand lens and have the knowledge in the record that there is water in a -- at a certain depth in one well that might carry over to another one because of the geology.

Q Okay. And circling back on your earlier statement, it would be necessary to have an understanding of groundwater depths for purposes of setting the surface casing, correct?

A Yes.

Q Okay. Also on page 45, you see the discussion of cathodic protection, where it states "Cathodic protection systems are commonly used to protect pipelines from corrosion and are sometimes used on well surface casing strings"?

A Yes.

Q What is your understanding of how cathodic protection works?

A Do you want a technical explanation or just something generic?

Q Your choice.

A Well, there is --

I guess you would look for a location that would be defined on an anode on a well casing or a pipeline, and a cathode location somewhere else. And the flow of electricity from one to the other can result in the removal of metal, usually iron, but also iron component of steel, from an unprotected pipeline.

So then when you do cathodic protection, you

basically reverse the polarity on that flow, on that electrical flow.

Q Also on page 45 you state "Cathodic protection would have provided corrosion protection to the 11 3/4-inch casing, but would not have protected the 7 inch casing inside the 11 3/4 inch casing."

Is that correct?

A Yes.

Q Why is it important in the context of your testimony and alleged violations that cathodic protection be applied to a surface casing if it would not have protected the 7-inch casing?

A Well, so the purpose of providing it to the surface casing was because that was what is exposed to water so more likely to corrode.

And what was the other half of your question?

Q That's fine. I can ask another question.

Did corrosion to the surface casing in your view cause the failure in the 7-inch production casing at SS-25?

A I'd have to go back and look at the details of the Blade report, but my understanding is that there was water entering the -- water entering the

casing at some point the surface casing or below at the 7-inch casing that was causing external corrosion; so I'd have to look at the drawing and tell you whether I could answer that specific question correctly.

Q Water also could have been coming up from under, correct?

A Coming up from under --

Q Under the shoe?

Could have been entering --

A Could have been, yes. It could actually just be produced with the gas. There is no telling how you can get water into a well.

Q So you're not contending that corrosion of the surface casing was the point of entry for water that caused the corrosion at SS-25 production casing?

A I am not. But Blade seems to think that that was contributing to it because they found the MIC in the -- as a cause of the corrosion, which would require some moisture; so I think they tied it to surface moisture or shallow moisture.

Q But you're not sure?

A I'd have to go back and look at it. It's been a while since I read that section.

Q Do you have prior experience with cathodic

protection?

A Well, I reviewed a lot of records with PG&E on cathodic protection. And before that we had cathodic protection on pipes at the oil refinery and at the chemical refinery where I worked.

And other than that, as a consultant, I think the only places I might have run into it is if there was cathodic protection on piping or underground storage tank systems that had to be disabled while we worked on them is all. I didn't have to operate it or analyze it.

Q Okay. So you reviewed records related to it; you didn't personally apply cathodic protection?

A No.

Q Or advise regarding installation of cathodic protection?

A I would call an expert in cathodic protection.

Q And in the cases you mentioned before, they were all pipeline cases; is that correct?

A Maybe underground storage tanks. I'm not sure.

Q What sort of underground storage tanks?

A It would be petroleum.

Q Are there any --

Is there any difference that you're aware of applying cathodic protection to above-ground pipes versus underground storage wells?

A I think it's a little bit more complicated for underground wells because they're vertical, and because you might have, like, SS-25 and 25A and 25B, co-located wells that will interfere if you don't design the system correctly.

Q How --

A But it's not impossible. It's just that it's a different application of cathodic protection.

Q Can you explain how you avoid interference with neighboring wells through system design?

A No. But I can look it up for you, and I can call an expert. And I think I provided some reference documents that included that information in response to DR 3.

DR 3? Your DR 3.

Q Data Response 3?

A Yes.

Q And those documents --

Did you prepare Data Response 3?

A Yes.

Q And you collected the documents --

A Yes.

Q -- for purposes of Data Response 3?
A Yes.
Q Do you recall when you collected those documents?
A After we received Data Request 3, whenever that was.
Q Is it your opinion that cathodic protection should be applied at the surface casings of all gas storage wells?
A I think it should be applied where there is a threat of corrosion. There may be instances where there is not.
Q There may be instances where there is no threat of corrosion in a gas storage well in the ground?
A Well, yes. I think that's possible.
Q Are you aware of any specific examples of that?
A I think actually in the Aliso field there might be some areas that they feel like would not require it, and then there is other areas where they think it's necessary.
Q But if there is a threat of corrosion, which would include, based on what you said previously, I'm guessing presence of water generally in the

environment, geology perhaps, you would believe cathodic protection is appropriate if there is a risk of corrosion?

A It certainly is a technology that should be investigated. There is other things you can do. You can put chemicals down the well. You can coat the casing if you happen to be drilling the well now and installing it. There --

You know, I think there are other things that you could do if you did not want to apply cathodic protection. But I do think that cathodic protection is the first thing that most engineers would look at.

Q In terms of putting chemicals down the well, what sort of chemicals are you referring to there?

A Well, typically it would be something like biocide, something to kill the MIC.

Q And that would generally protect against corrosion of the internal diameter of the casing, correct?

A Yes, won't help you with the external.

Q And in terms of the specially-treated casings, that's --

A External.

Q That's external --

A It could be external and internal.
Q But again for newly-drilled wells --
A Well, yeah, if your casing is already --
Q -- not for existing wells?
A -- in ground and cemented, you're not going to be able to do it.
Q Thank you.
Is it your opinion that SoCalGas should have cemented the production casing at SS-25 all the way to the surface?
MR. GRUEN: Objection. Just vague as to time.
BY MR. STODDARD:
Q Is it your contention that SoCalGas should have cemented the surface casing at SS-25 all the way to surface sometime after it acquired the field?
A It would have been a prudent thing to do.
Q For existing wells that are in gas storage fields in California that are not cemented to surface, do you believe that those wells should be cemented to surface to protect against the risk of corrosion?
A You mean should they be done -- should it be done now?
Q Should it be a retrofit?
A I think it's an economic assessment that

needs to be done there to determine what the risk is of leaving it as is versus cementing it and having the protection for the rest of the life of the well. And some of those wells are pretty old; maybe it's not cost effective. Maybe you're going to be shutting them down pretty soon anyway and replacing them.

Q So cost effectiveness of the measure would be relevant to the consideration of whether it should be done?

A I think so. But also risk assessment. If there is a risk of it blowing out, that could be part of your cost-effective calculation.

Q Would you contend that a failure to cement an existing well to surface would be a violation of 451?

A Probably depends on the specifics of the well.

Q Including cost effectiveness.

A Well, for a 451 violation, I think we would look at the risk primarily of there being a failure that would create a problem at the surface.

Q As well as feasibility of the operation?

A Feasibility would certainly be part of the equation.

Q Would assessment of risk include past success with addressing well failures and leaks?
A For example? What do you mean?
Q If an operator had -- historically had success with identifying leaks and repairing them as they arose, would that be relevant to your consideration as to whether it would be a violation of 451 if they chose not to cement the casing to surface?
A So we're still talking about casing, the surface casing?
Q Sure. Uh-huh. No, I'm sorry, the cementing.
A "Cementing"?
Q Yeah.
A So if they had a good record in the past of fixing leaks in surface casing that was not cemented, would that be relevant to the decision not to cement?
Q Let me restate this.
A Okay.
Q And let's limit this to the cementing issue.
A Okay.
Q You said that --
We talked about how cost effectiveness would be one factor in considering whether or not to cement

to surface.

You said risk assessment would be another factor?

A Yes.

Q My question is whether part of that risk assessment would include past success with addressing and fixing leaks as they arose.

A I wouldn't give that a lot of weight unless in the process there had been determination of what the cause of those leaks were; so you could accurately forecast whether or not the problem was going to continue with other wells.

So if all they're doing is patching things to keep -- and well after well is failing for the same reason, but they don't know the reason that it's failing, then you would know things are going to continue to fail. And in that instance, the fact that they're successful at plugging holes in wells doesn't really help with a risk assessment, because the risk continues for other wells. They're going to continue to leak if you don't know how to stop the cause of the leaks.

Q Is that true if the consequences of those leaks are not significant?

A Well, I suppose SoCalGas might be able to

categorize some leaks as not consequential or not important and others important. But I'm not aware of how they would do that.

You know, a failed well is a failed well, and you have to fix it. And if you don't want it to happen to the next well over, then you need to find out why it failed.

Q Speaking hypothetically and abstractly, frankly not even in the context of gas storage operations, would you agree that a risk assessment should include both the likelihood of a given event and the consequences of the event?

A That's a typical statement for pipeline risk assessments.

Q Okay. Moving on to page 47 of the same exhibit. This violation -- alleged violation is related to -- stated as "SoCalGas lacked a real-time continuous pressure monitoring system for well surveillance, which prevented an immediate identification of the SS-25 leak and an accurate estimation of the gas flow rate."

Are you familiar with what other gas storage operators do with respect to real-time pressure monitoring?

Let me restate that.

Are you familiar with what other gas storage operators did as of October 23, 2015 with respect to real-time pressure monitoring?

A No. I did not look into that. This is based on the Blade report and what they determined.

Q What is your understanding of what SoCalGas would have done or could have done had they immediately identified the leak due to real-time pressure monitoring?

MR. GRUEN: I'm going to --

MR. STODDARD: I'm sorry, I'll restate that.

Q If SoCalGas had been able to immediately identify the leak because of a real-time pressure monitoring system, what do you contend SoCalGas could have done that would have helped mitigate the consequences of the incident?

MR. GRUEN: I'm going to note an objection to the extent this is calling for Ms. Felts to recommend fixes or recommend investigations.

Again, this is outside the purview of SED and it is -- so it's beyond the scope of what SED is called to do.

But Ms. Felts can answer the question.

THE WITNESS: Okay. Just a minute. Let me see what Blade said on this.

Okay. So on page 48 there is additional information about that.

BY MR. STODDARD:

Q Would you please read?

A In the third paragraph, "The lack of real-time pressure measurements prevented the immediate identification of the 7-inch casing failure."

I guess you might have to read the paragraph ahead of that to get the context.

"But constant monitoring of the tubing production casing and surface casing pressures will provide better insight into operational deviations in all wells."

So I think here the concept is that if you have real-time data, you would be able to see exactly what was going on in the well, and because they didn't have that, they were somewhat hampered in being able to detect a leak before it actually broke out to the surface and they started to smell it, which I think is the way they detected it.

So this is a plan, an idea of how SoCalGas could have been monitoring the system to see the -- see the leak in an operational data manner rather than just waiting until it leaks to the surface.

Q I understand how -- your response, I believe, describes how continuous real-time pressure monitoring would have enabled identification of the leak at an earlier time.

A Right.

Q What would that identification have enabled SoCalGas to do in response?

A Their response would probably still be to shut down the well and I'm guessing and to start a well-kill process. It's probably Blade's thought on this, and I think you would have to ask Blade, that an earlier detection might have prevented some of the damage from occurring and might have allowed the first -- the initial well kill to be successful. But here again, I think you should ask Blade that question, not me.

Q Well, it is your testimony; so I'm going to ask you.

How would shutting the well immediately have prevented further damage in your view?

A Well, this well was already leaking through the casing when they shut it down, whereas -- I mean, significantly leaking. If they had been able to detect a smaller leak first, they might have had a better outcome on their original well kill. That's

my read on it.

Q How much earlier do you think that would have needed to be? Are we talking minutes, hours, weeks?

A I would --

I don't know because I don't know how fast the problem within the well was occurring. But my understanding is that the real failure that caused -- caused the detection outside of the well on that day was fairly sudden.

I mean, the loss of gas at that -- in that amount was a result of a fairly sudden event within the well.

On the other hand, microbial corrosion and small leaks through holes is not sudden. And so it's possible they might have picked up a problem earlier, maybe even weeks earlier, through regular monitoring.

Q So a continuous real-time pressure monitoring system would have been useful in identifying development of a leak over a period of time?

A Right. Or a major leak. I think you would be -- you would be looking at a leak, but a major leak might be preventible.

Do you understand?

Q A major leak might be preventible if you catch it early?

A Yes.

Q As it's developing?

A You would catch a smaller leak earlier, right.

Q Okay. Separately the second part of the statement in paragraph 8 on page 47, the first is the immediate identification of the leak, which we discussed. The second, an accurate estimation of the gas flow rate.

Can you explain why continuous real-time pressure monitoring is necessary for accurate estimation of the flow rate?

A If they had detected the well, the problem earlier, they would have been able to shut in the well, avoid the catastrophic failure of the pipe casing, and then they might have had a better chance of being able to estimate the gas flow rate or would have had a better measure of gas flow at the time the well was shut in.

So what they did was they let the well fail for lack of monitoring, and once it failed and was blowing out, up the side of the casing, there wasn't a way to measure the gas flow rate.

Q So you don't believe that they could get accurate -- or that --

You are aware that there are pressure gauges on the well head and on the casing?

A Yes, but that was useless once the well blew out.

Q Why is that?

A Because the gas was coming up outside of the well. It wasn't coming up through those, past those instruments anymore.

Q And prior to the blowout?

A Well, prior to the blowout they had measurements of the flow in and out of the well through the piping and the instrumentation. After the blowout, that instrumentation wasn't useful.

Q So what would a continuous real-time pressure monitoring system have provided that they couldn't have collected prior to the blowout?

A The way I connect this is that the real-time monitoring system would have probably prevented the blowout because they would have detected the leak at a lesser amount and shut in the well; so they would have had their readings at that point in time. But if they shut in the well, they wouldn't have to use the readings. They would have the flow, but it's

kind of --

Q So it's more about the ability to shut in the well and prevent further development of a smaller leak into a bigger leak --

A Right.

Q -- than it is about the flow rate?

A I think so.

Q Okay. But you're not sure?

A Well, because that seems to be tacked onto there, and I don't know why, I would have to go back and look at it again to see how that developed.

Q I don't know either. I'm sorry, I interrupted you.

I mean for purposes of this violation, you would agree that you're relying heavily on the Blade report, correct?

A Yes.

Q Entirely on the Blade report?

A This one is from the Blade report, yes.

Q And maybe you don't fully understand what Blade was saying on this issue.

A I think the -- I think the caption here was refined from the Blade report, and so it looks to me like two issues are merged together here.

But since it's all one violation, I don't

know if it makes any difference if you drop out the accurate estimation of gas flow rate, it's still the same violation.

Q So you believe you understand and have accurately stated Blade's position with respect to preventing development of a leak over time by shutting in a well?

A I think the following -- the text that follows that heading -- the heading is a little weird, but the text that follows it I think accurately represents what Blade said.

Q Do you believe, Ms. Felts, that it's important or critical when you're asserting violations that you have a good understanding of the underlying facts related to and supporting those violations?

A Sure.

Q On page 50, it says in the middle paragraph, "Industry technology has evolved for real time pressure, temperature, flow, and vibration monitoring but, surprisingly, there were no significant differences in the monitoring plan from 1989."

Do you see that sentence?

A Yes.

Q How has industry technology evolved -- let

me restate that. I'm going to break these into separate questions.

How has industry technology evolved for real-time pressure monitoring?

A Well, I think over a period of time the accuracy and reliability of any instrumentation that might be used on a well has improved.

Q How has technology evolved for temperature monitoring?

A I would say not a lot. It's still pretty much the same log. There may be more accuracy in the feedback on the log. But basic technology is the same.

Q So then the statement you don't agree with?

A I don't not agree with it. I am just not aware of whatever Blade was aware of. It's footnoted to Blade's report, and apparently they have an opinion about that that you could ask them about.

Q Turning to page 51, Section C. "Additional Violations," Number 1 is "SoCalGas Knew That SS-25 Released Both Crude Oil and Natural Gas During the Aliso Canyon Natural Gas Storage Incident, But Did Not Disclose This Fact to the Los Angeles Department of Public Health."

Do you see that section?

A Yes.
Q You weren't personally involved in any discussions with DPH related to this issue, were you?
A No.
Q What did you do to get yourself comfortable with sponsoring your testimony on this issue?
A Originally my understanding was that the Department of Public Health was going to sponsor this section and would support it, and so I didn't do anything other than read it. But I do have a background in environmental technologies, environmental issues, and so I felt like I was pretty comfortable with supporting it.
Q But you didn't have personal knowledge relating to the Department of Public Health's specific dispute here with SoCalGas, correct?
A The only thing I had were the letters that went back and forth that were provided to me. I think they're attachments.
Q If you turn to page 52, do you see the last sentence of this section which says "These dates and the precise nature of this violation may be modified pending additional testimony from intervening parties to this proceeding with expertise in public health"?
A Yes.

Q Intervening parties based on your prior statement, I understand that intervening parties to this proceeding with expertise in public health was DPH?

A That was my understanding.

Q Were there other potential parties that you were aware of?

MR. GRUEN: Objection. Calls for speculation.

BY MR. STODDARD:

Q Were you aware of any other parties that were being actually -- no, I'm going to restate it.

Were you aware of any other parties that were considering intervening in this proceeding on this issue?

A As interveners.

Q The sentence says "These dates and the precise nature of this violation may be modified pending additional testimony from intervening parties to this proceeding with expertise in public health."

I'm asking whether "parties" there refers to anyone other than DPH?

A I don't know.

Q You're not aware of anyone else that would have been?

A I was not told of anyone else.

Q Okay. Did you draft this sentence?
A No.
Q And it's your understanding that there was an arrangement by which DPH would come and provide the supporting factual basis for this violation?
A Yes.
Q You indicated that you reviewed letters related to this violation; is that correct?
A There is at least one letter from DPH to SoCalGas and one from SoCalGas to DPH that I believe were attachments to this testimony that I read.
MR. STODDARD: I'm going to introduce Exhibit 1-31.
(Deposition Exhibit 1-31 was marked for identification and is attached hereto.)
BY MR. STODDARD:
Q Do you recognize this document, Ms. Felts?
A Yes.
Q You reviewed this letter?
A Yes.
Q And you considered SoCalGas's arguments outlined in the five paragraphs on pages 1, 2 and 3?
A Yes.
Q Did you discuss with Darryl whether or not

to include this violation based on SoCalGas's response?

A I looked at this letter, and then I looked at actually --

I was going to say that I looked at the analysis that SoCalGas did, but that was after the testimony came out. So I had this letter. I think that the main thing that I discussed with Darryl was that it was the statement on page 2, it says the --

See on page 2, the second full paragraph says, "Consistent with those statements air samples taken by DPH and other agencies during and immediately after the incident were analyzed for compounds that are typically found in crude oil, including benzene, toluene, ethylbenzene and xylene," which is typically referred to as BTEX.

That statement concerned me because naturally those four things are typically found in crude oil, but they would not necessarily tell you what heavy components of oil might be dropping out of the air emissions from the well.

So I felt like this is only a partial -- a partial answer, that it seemed like DPH had asked for a more extensive analysis of the air emissions, the gas emissions and didn't get it.

Q As framed the violation relates to a failure to disclose, correct?
A I understand that, and I agree with you, yes.
Q Okay. Thank you.
Turn to page 52, please.
A Okay.
Q See paragraph 2, "In Multiple Instances, SoCalGas Did Not Cooperate with SED During Its Pre-Formal Investigation Following the Incident on Aliso Well SS-25 that Began on October 23, 2015."
Do you see that paragraph?
A Yes.
Q You were not personally involved in SED's preliminary investigation, correct?
A No.
Didn't we discuss this earlier? Seems like we've already been through this one.
Q Not what we're about to discuss.
A Okay.
Q Did you --
And again, to confirm though, you didn't talk to anyone related to these violations other than Mr. Gruen, correct?
A That's correct.

Q Okay. With respect to SoCalGas's failure to produce Boots & Coots witnesses for an examination under oath, what did you review?

MR. GRUEN: I'm sorry, is there a particular area of testimony that you're asking about?

THE WITNESS: I think it must be back --

BY MR. STODDARD:

Q See page 55 if you need to.

A There are letters referenced in the footnotes 390 and 391.

Q So a letter from SED Director Malashenko and again another letter from SED Director Malashenko.

A Yes. Let's see if there's more.

On page 56 there is additional footnotes. And I did not see subpoenas, I did see correspondence.

Q You didn't see the subpoenas because they weren't included, or you didn't review them?

A I didn't review them.

Q In your practice as an attorney, have you ever propounded subpoenas on witnesses?

MR. GRUEN: I'm going to object to relevance here.

THE WITNESS: Not related to utilities.

BY MR. STODDARD:

Q In any context?
A A couple of times.
Q Have you ever provided a subpoena on another party to compel appearance of a third party?
A No.
MR. GRUEN: Same objection.
MR. STODDARD: I'm going to introduce Exhibit 1-32.
(Deposition Exhibit 1-32 was marked for identification and is attached hereto.)
BY MR. STODDARD:
Q Do you recognize this document, Ms. Felts?
A I think I've seen it before.
Q If you turn to page 56 of your testimony, you'll see this letter excerpted starting at the bottom of 56.
A Yes.
Q And continuing all through page 57 and 58.
A Yes. Right.
Q We would note that despite the liberal quotation, it excludes most of the discussion -- actually the entire discussion of law from the letter.
If you will reference page 3 of the letter

itself, Exhibit 132.

A Okay.

Q Do you see what --

Do you see that there the discussion of law starting with reference to Snyder v. Southern California Edison?

A Yes.

Q And you agree that that is not included in this testimony?

A Yes.

Q Do you recall reading this?

A I -- I read it. I didn't spend a lot of time on the law part.

Q But you considered it?

A Yes.

Q And do you agree that SoCalGas cannot legally compel appearance of a third party --

MR. GRUEN: Objection.

BY MR. STODDARD:

Q -- without legal process?

MR. GRUEN: Objection. Calls for legal conclusion.

You can answer if you're able.

THE WITNESS: My participation in this testimony is technical, not legal.

BY MR. STODDARD:

Q So you can't testify to the facts in this violation?

A To.

MR. GRUEN: Objection. Mischaracterization of testimony.

BY MR. STODDARD:

Q Are you able to testify to support this alleged violation?

A The violation is just as I read it, that you refused to produce a witness over a period of time when you were requested. That's factual. The argument underlying that is legal, and I did not develop that or spend any time reviewing it; so my part of the testimony is only on the facts.

Q But you have yourself prepared and served subpoenas, correct, for appearance of witnesses?

A Yes. I don't know how that is relevant in this particular contract that I have with the PUC.

Q Well, you're aware how subpoenas work?

A Yes.

Q Okay. And you've never, between --

To restate what you said earlier, you've never served a subpoena on a third party -- on a party for production of another party?

MR. GRUEN: Objection. Asked and answered.
THE WITNESS: No.
BY MR. STODDARD:
Q Do you believe it should be a violation of law if SoCalGas is compelled to do something that is not within its legal power to do?
MR. GRUEN: Objection. Calls for legal conclusion.
THE WITNESS: Yeah.
MR. GRUEN: I've got to say, this is -- it's --
We've been here cooperating, now it's going on the -- I think the eleventh hour, and now we're continuing to discuss calling for legal conclusion.
We agreed to come down here and do this deposition.
MR. STODDARD: You asked to come down here and do this deposition, it was your request.
MR. GRUEN: We agreed to do the deposition.
Let's not mince words. We agreed to do the deposition, but we're going on and on.
And we did not agree to come down here and provide Ms. Felts to answer questions that are calling for a legal conclusion. That's beyond the scope of what we've agreed to do here.
If we're going to keep going down this

road --

I think this line of questioning about legal conclusions and what her views are on the law should wrap up maybe in a question or two.

MR. STODDARD: Are you instructing the witness not to answer the question?

MR. GRUEN: No, she can answer. But the line of questioning is wasting our time.

MR. STODDARD: Darryl, we were happy to come to San Francisco, you guys wanted to do it down here.

We have a right to our deposition.

MR. GRUEN: That's --

MR. STODDARD: And she has asserted violations that -- a lot of them are based, frankly, on law. And the truth is, if she can't testify to those facts, we would ask for a witness.

MR. GRUEN: That is completely mischaracterizing what I'm saying.

I'm going to read for the record in light of this -- if you'll indulge me, we're going to have to go here, I hoped we wouldn't. But bear with me a second.

Can we go off the record for a second?

MR. STODDARD: Actually, in the interest of time, because I know we want to keep moving, can I

try restating the question and see if your objections continue?

MR. GRUEN: Of course.

MR. STODDARD: All right.

Q Are you aware of any authority that would permit SoCalGas to compel production of a third-party entity?

MR. GRUEN: I'm going to restate the objection and I'm going to note here that --

I'm going to read a quote from the pre-hearing conference statement, the transcript, at pages 43 and 44, that we -- that captures the understanding that we've had.

Unfortunately -- so this starts to quote ALJ Kenny.

"The next question concerns the deadline for SED to submit alleged violations and the factual and legal justifications for each alleged violation. My question is whether it would be reasonable to set a deadline of opening testimony for SED to submit alleged violations and the factual justifications for each alleged violation and set a deadline for

opening briefs for SED to submit the legal justifications for its alleged violation.

"Would any apparent like to respond to my question? SoCalGas."

Quoting Mr. Stoddard:

"SoCalGas's position on this is that SED should identify the alleged violations with specificity in its opening testimony sooner, if possible; but in its opening testimony would be acceptable to SoCalGas as we had proposed in our prehearing conference statement."

My co-counsel, Mr. Sher:

"Your Honor, SED would not necessarily be opposed to such if SoCalGas agreed that now that it would not waste time cross-examining SED's witness as to their legal basis for tying violations to code sections, et cetera."

"ALJ KELLEY: Does SoCalGas have a response at this time?

"MR. STODDARD: SoCalGas is not

going to waive any rights to cross-examination. Although I would ask for clarification what exactly is meant by 'legal basis' here.

"MR. SHER: The way your Honor set this out is that the violations would be set forth in the opening. And then the legal issues" --

I might highlight the legal issues there, continuing the quote --

-- "would be discussed in the briefing. To the degree it is likely" -- "highly unlikely that SED's witness would be a lawyer, so we don't want SoCalGas, if we are going to do this all in our opening testimony, to cross-examine the witness as to their legal basis for concluding that this is a violation, for example 451.

"MR. STODDARD: SoCalGas does not object to that."

Thank you.

It was SED's understanding that preparing the violations at SoCalGas's request would not lead to a set of questions of the witness as to the legal

analysis that would be required to support them underlying the testimony. These are briefable issues. That's why I'm recommending that we move on, we cut this line short.

If you want to continue with this line of questioning, we're here, but we maintain that this is a waste of time to do it here.

MR. STODDARD: An important part of that that you read was Nicholas's statement that your witness was not likely to be a lawyer, and it was -- part of it, what he said there was predicated upon that representation. First.

Second of all, this isn't cross-examination, this is discovery.

Third --

Can I see this?

-- this issue has been addressed before in front of the Commission. This is a transcript in which Ms. Felts was a witness in the PG&E San Bruno proceeding.

Are you familiar with this?

MR. GRUEN: I haven't seen the transcript that you're referring to. I don't know if I'm familiar or not. I'm sorry.

MR. STODDARD: Counsel for PG&E, Joe Malkin, was

representing -- was representing PG&E, and Bob Cagen was opening ORA. Bob Cagen stated an objection to a line of questioning related to Rule 1, said "Excuse me, Your Honor, I think I'm going to object to this. This really is calling for a legal conclusion rather than anything else that is valuable in the way of fact finding."

Joe Malkin said "Well, Your Honor, this witness has told us that she is advocating that the Commission find PG&E guilty of this Rule 1 violation. I am probing her thought process and what underlies her advocacy to the Commission. And to the extent that Mr. Cagen is concerned that we're sliding over into legal opinions, as you heard yesterday, Ms. Felts is, in fact, a lawyer; so the objection of a legal issue being addressed today by a non-lawyer, which was raised by Ms. Halogan yesterday, doesn't apply."

And the judge said "Okay. I'm going to allow it. Go ahead."

And the judge in this case was your co-counsel, Amy Yip-Kikugawa. And --

MR. GRUEN: Can I have an opportunity to respond to that?

MR. STODDARD: -- the discussion we had at the

pre-hearing conference was not reflected anywhere in the judge's scoping ruling.

Ms. Felts is asserting violations of law throughout her testimony. You had the ability to scope your testimony however you saw fit and you chose to do it that way. And you included law, but you also included conduct. And the question that we're asking relates to the connection of the conduct and the law.

MR. GRUEN: If I may.

I appreciate you raising the issues.

I will note that SoCalGas, in its response to our request to provide a person most knowledgeable related to the -- the SoCalGas's alleged assertions regarding Mr. Bruno. In response to our request for a deponent, we had understood that SoCalGas had only attorneys and argued that it couldn't provide someone on that basis was our understanding.

And when the ALJ ruled that, in fact, SoCalGas was to provide a non-attorney, SoCalGas continued to provide someone who is, in fact, an attorney. I understand he is not in that role as a represented counsel. However, Mr. Jason Egan, according to my last checking on the State Bar of California website yesterday, is indeed a licensed

attorney, and yet he is being provided to provide testimony in that deposition; so it's the same thing, yet our understanding, per the ruling, is he was provided as indeed a non-attorney in compliance with the ruling, similar to what we're doing here.

I understand there are a number of attorneys practicing for SoCalGas who I've had the ability to come in to work with who indeed are attorneys but don't appear or practice as designated counsel for SoCalGas. That's one.

Two, it remains our position that questions about discovery for purposes of this exercise are no different, are no different than cross-examination; so this line --

It is for the purpose -- to the extent this is for the purpose of determining cross-examination, we maintain there is no distinction. That's a distinction without a meaning.

We think that this --

We distinguish from San Bruno, this is its own set of facts and circumstances. We came to an agreement and understanding in reliance that SoCalGas on the record at the pre-hearing conference wanted SED to produce violations right away, and that we would have the ability to brief the violations. We

didn't have to do that, SED didn't have to produce violations.

There is no telling had we not come to this resolution what the ALJ would have instructed. But we've done so, and we are concerned that SoCalGas frankly is not in good faith in asking these questions at this time and asking for the basis for legal conclusion.

So with that, that's our response. That remains our position. It's not appropriate to be asking Ms. Felts these types of questions here.

But with that, you can continue with your line of questioning.

MR. STODDARD: I'd like to make a couple of other remarks for the record.

Frankly, I don't understand your point about Jason Egan, but we can move on from that.

Secondly, I don't know that it would be necessary to be asking Ms. Felts these questions if SED responded to our written discovery along the same lines, where we've asked you to explain legal basis and positions which SED should be capable of doing if it doesn't want to subject its witness to those questions.

One of the reasons for asking questions

related to legal basis or contentions or anything else is to help narrow the parties -- the scope of issues in dispute and bring the parties together for purposes of determining the issues that actually should be litigated in an evidentiary hearing.

Everything in here that has been alleged related to the Boots & Coots violation, is simply related to SED's misunderstanding of the law. And we are trying to ask questions about that so we can better understand what your position is.

MR. GRUEN: I'm going to object to that characterization as mischaracterizing SED's testimony. That's just simply an inappropriate mischaracterization.

I'm sorry if you don't understand our point about Mr. Egan, we can go back on the record and understand it. I don't know how to articulate it any better, Jack. I'm sorry that it has to come to this.

But we're here. If you want to continue to ask questions, we --

Again, we don't think this is appropriate to continue down the road of asking about legal conclusion, but if you're going to do it for purposes of the deposition, then continue with your line.

MR. STODDARD: I hadn't finished what I was

saying, but I will continue my line of questioning in a moment.

The next --

The only other thing I wanted to mention, just in case it was unclear, was we aren't conceding anything with respect to cross-examination. I was simply noting that this is not a cross-examination.

Again, our reading of what occurred -- you know, our reading of ALJ Amy Yip-Kikugawa's ruling at the San Bruno case we think is applicable here. We don't think that the judge relied on that discussion for purposes of the scoping ruling. And if we have to go to the judge over this, we can.

MR. GRUEN: We're agreeing to answer questions.

I would say it's also a mischaracterization to call Amy Yip-Kikugawa my co-counsel. She is an Assistant General Counsel at -- and she is my direct supervisor. She is not an assigned counsel to this proceeding.

Just to make it clear, that's Nicholas and myself. We're the designated counsel of record, just to clarify.

And the ruling there has, to my -- and you can enlighten me, there has been no ruling saying that Ms. Felts has to answer questions regarding

legal conclusions, that call for legal conclusion. But if you want to take that to the judge, we understand, and we can handle the issue that way.

Like I said, she is available to answer questions at this point.

MR. STODDARD: Okay.

Q Turning to page 54, Ms. Felts.

A Okay. I'll get it later.

MR. GRUEN: Okay.

BY MR. STODDARD:

Q This alleges four violations related to alleged data dumps of documents on Blade.

A Yes.

Q Did you review the contents of these data dumps?

A I have reviewed some of it, but I have not reviewed the actual files that Blade received. I believe I have reviewed some of the documents that were in possession of the PUC that were similar.

Q And you didn't interview Blade regarding the context of the data dumps, did you?

A No.

Q Did you review any correspondence between SoCalGas and SED on this issue, including data responses?

A On this issue?
Q Yes.
A What data response would it be, could you tell me?
Q We can follow up with that.
But do you recall as you sit here, reviewing a response to a data dump?
A I think I did review some things, but I can't tell you what data response it was in or what the extent of the documentation was.
Q Okay. For purposes of the record, it looks like I didn't actually get an answer to my question prior to the exchange with Mr. Gruen; so I'm going to ask it again, and we can just get it on the record.
Are you aware of any authority that would permit SoCalGas to compel production of a third-party entity?
MR. GRUEN: And re-note the objection as calling for legal conclusion.
THE WITNESS: No.
MR. STODDARD: Thank you.
Q With respect to the Blade data dump we were just discussing, you indicated you may have reviewed some of the documents?
A Yes.

Q Did you assess materiality of the documents to Blade's RCR report?

A I don't know what that means.

Q Did you consider whether or not the documents had bearing on any of the issues that Blade reached conclusions on in their Blade -- in the Blade report?

A I think I answered that question when I discussed the apparent lack of temperature surveys or their -- the fact that they appeared not to have them until review for Well SS-25. Other than that --

And they said they didn't have permeability of the reservoir, which wasn't in the Well 25 -- SS-25 file anyway. I would say that most of their conclusions were based on their own work with the well and their own investigation into the well casings, their groundwater monitoring wells.

So they developed most of their own -- their own information. It's possible that had they had the time to look at all of the data that SoCalGas provided them, they might have had additional information to inform them on more details of the case. I just don't know.

Q Thank you.

When did you review the data doc -- data

dump documents that you reviewed?

A I didn't -- I didn't review anything other than that one well file prior to filing the testimony.

Is that what you mean? I mean, you're talking about SoCalGas records?

Q Yes.

A Yes.

Q Ms. Felts, circling back to the privilege violations, and if we don't -- if we have to reference the testimony, we can. But we can speak without a document if we're able to.

You're aware that each alleged privilege violation is framed as both a violation of 451 and 1.1, correct?

A Yes.

Q Can you explain why in your view each privilege violation is -- constitutes a violation of Public Utilities Code 451?

MR. GRUEN: Objection. Calls for legal conclusion.

Can we go off the record for a second?

MR. STODDARD: You've stated your objections, Darryl.

MR. GRUEN: I know.

MR. STODDARD: Are you going to let us ask her a question?

MR. GRUEN: Absolutely.

We have --

MR. STODDARD: We can go off the record.

MR. MOSHFEGH: There is a question pending.

THE VIDEOGRAPHER: Just a moment.

MR. GRUEN: Okay. We can wait until the question is done.

THE VIDEOGRAPHER: Go ahead.

THE WITNESS: Okay. 451 is related to safety, so a duty to operate safely. Is that --

Do you want more?

BY MR. STODDARD:

Q So did you determine that the documents here that were withheld jeopardized safety?

A The concept was that you -- the delay in getting the documents created an unsafe situation because there was no way to respond to the documents without -- or to use the documents unless they were provided.

Q Would it be relevant to your opinion on these violations if --

I asked earlier several if several of the documents were duplicates, as you'll recall.

Would it be relevant to your opinion on these violations if many of these documents were already in SED's possession?

A I -- I have to wonder why we don't have them, what the purpose of not disclosing them is. If we already have them, why couldn't you just tell us we already have them.

Q For example, attachments to emails that would have been otherwise privileged, attachments to privileged documents are privileged, but they're included for purposes of the calculation of penalties.

A Is that how they ended up being pages?

Q Is that relevant in your view to the assessment of a violation in this instance?

A I think it's probably relevant. You have to have all of the information in order to count.

MR. GRUEN: If you finished that line, can we go off the record now for a moment?

BY MR. STODDARD:

Q Do you know what, if anything, SED would have done differently had it received these documents earlier?

A You might not have that violation.

Q Do you know what, if anything, SED would

have done differently with respect to their investigation?

A Not without knowing what the -- what the records are.

Q The records that were produced to you, which are in your possession, these are the documents that the privilege violations are based upon.

A Oh, and that have now been produced?

Q Yes.

A Without looking at each one of the documents, I can't tell you what --

I was never asked to look at them in that manner.

Q Are you aware if any of the documents are relied upon in your testimony in any citation or exhibit for purposes of supporting other alleged violations?

A I don't know. But I don't think so.

MR. STODDARD: Okay. Thank you. We can go off the record.

THE VIDEOGRAPHER: We are off the record at 7:42 p.m.

(Off the record.)

THE VIDEOGRAPHER: We are back on the record at 8:06 p.m.

MR. STODDARD: All right, Ms. Felts, I'm going to promise to keep this short hopefully. But we'll be jumping around a bit just because this is kind of the scraps at the end, so bear with me.

Q To begin with, I'm going to ask, do you consider yourself, Ms. Felts, an expert on attorney-client privilege?

A No.

Q Are you aware of any hard drive of Blade data that was produced to SED?

A Yes.

Q And have you accessed that?

A No.

Q So you haven't reviewed any of the records that are on that drive?

A Not yet.

MR. STODDARD: Okay. I'm going to introduce Exhibit 1-33.

(Deposition Exhibit 1-33 was marked for identification and is attached hereto.)

BY MR. STODDARD:

Q Do you recognize this document, Ms. Felts?

A Yeah, it looks like something I wrote.

Q This is an email from you --

Well, to be clear this includes two emails: The top one is from you to Karen Shea and Darryl Gruen, and it includes an attachment "Draft Data Request"; is that correct?

A Yes. Well, that's what it looks like.

Q And the bottom email is also from you to Karen Shea, and it appears to be related to the draft data request as well?

A Yes.

Q Turning the page, in referencing the attached data request, and again, this is just for purposes of the record, Exhibit 1-33, the email dated November 8, 2019, and the draft data request, the first data request is for -- it asks to provide a summary of all data requests that SoCalGas has received related to I1906016, including those received from the CPUC before and after the initiation of investigation from DOGGR Blade and third parties; is that correct?

A Yes.

Q Did you prepare that request?

A Yes.

Q Why did you prepare that request?

A At the time I understood that the data that was available at the PUC was incomplete, an

incomplete set, and it was also not readily accessible to me. And so there was some discussion back and forth about how to get a full set of data.

Q And was it not --

Was it incomplete and not accessible in part because of the corrupted files you referenced earlier?

A That's part of the issue. Things wouldn't open. Other issues were there was some thought that some of the data that had been provided by SoCalGas in thumb drives may not have been uploaded. I don't think that was the case.

But at the time -- at the time when I couldn't find it on the Diamond database, that was mentioned that they thought maybe, maybe they weren't uploaded.

Later I found out that it was just organized a different way, and I was able to find some of it. Did not solve the corrupted files problem.

Q Was any of the data lost, to your knowledge?

A What do you mean by "lost"? Like did they lose a thumb drive?

Q Or was it, you know, simply not in SED's possession despite the fact that it appeared it had been transmitted to SED?

A I can't really tell you that. I don't have a good feel for what came in, what should have been uploaded and what should not have. I just don't have a good solid sense of what all SoCalGas provided. And I wanted to get it directly from SoCalGas again, but apparently you said no; so then we took steps to try to get a set of data from -- directly from Blade, and that was difficult too.

Q In the course of preparing this request, I imagine you had conversations with Ms. Shea and Mr. Gruen about the need to ask it?

A Yes.

Q Including discussions about how you could access the data, correct?

A Yes.

Q And where it was?

A Yes.

Q In the course of those discussions, did anyone indicate that the data had been lost?

A There was a thought that -- not that it had been lost but that maybe it was not uploaded. There was also a comment that the thumb drives had been uploaded and then discarded. Because we thought maybe if we could get the thumb drives, I could look at it directly from those. But I have not been

provided any thumb drives.

Q Why couldn't you --

If it had been uploaded from the thumb drives, why couldn't you look at the data that was uploaded?

A Well, because the files weren't opening. And a lot of the larger files were opening with the message that said the file was corrupted; so there wasn't any way for me to recover it.

Q Do you recall from those discussions any reference to FTP transfers?

A We talked about this earlier. I had --

I got capability to do FTP out, but there was no discussion about --

Q I'm sorry, I'm asking a different question.

A Okay.

Q We did talk about it earlier, correct?

A Yes.

Q I'm asking whether --

You mentioned that SED had received files from SoCalGas via thumb drive?

A Yes.

Q Are you aware whether SED also received files from SoCalGas via FTP?

A No.

Q Okay. So you don't recall any discussion about expired FTP transmittals?

A I think somebody --

Actually, I think I received a link maybe from Karen or Darryl that had expired. I tried the link.

Q Thank you.

Ms. Felts, we were discussing casing inspection logs earlier.

Do you have any personal experience with the Vertilog tool?

A Other than just reading logs? No.

You mean like running a wire line test or -- and generating one?

No.

Q How about interpreting logs --

A Yes.

Q -- Vertilogs specifically?

A I have read those, yes.

Q And in what context?

A Well, beginning in school I had a whole course on that, and then over a period of time I have had occasion in private consulting cases to look at well logs.

Q Again, we're talking specifically about

Vertilog logs here.

A Well, I think a Vertilog is one of many different kinds of logs; so I'm sure I've looked at them. I just can't tell you exactly which case, what date.

Q And what is your understanding regarding the reliability of Vertilogs -- the Vertilog tool?

A There were probably some issues with them over time. They've probably gotten a lot better recently.

Q Okay.

MR. STODDARD: Introduce Exhibit 1-34.

(Deposition Exhibit 1-34 was marked for identification and is attached hereto.)

BY MR. STODDARD:

Q In connection with Exhibits 1-17 and 1-18. Ms. Felts, do you recognize this?

A No.

Q This is the metadata file for an email for the document attached to the Tuesday, November 19th, email from Darryl to you, if you reference Exhibit 1-17 and Exhibit 1-18.

A 1-17 and 1-18?

Q Correct.

Do you have 1-18 there?
A I have 1-18.
Is that good enough?
Q That's good enough.
A Okay.
Q This is the metadata file for document 1-18, which is the draft testimony that was transmitted to you by Darryl Gruen, and this is SED's portion of the testimony.
A Okay.
Q And you'll see there that identifies the manager author as Randy Holter.
A Uh-huh.
Q And you don't know and haven't spoken to Randy Holter, correct?
A No.
Q And the secondary author it identifies, last modified -- the document was last modified by Darryl Gruen.
Do you see that?
A Yes.
Q And it doesn't identify any other authors?
A Okay.
Q Do you see that?
A Uh-huh.

Q Ms. Felts, seeing this and having gone through the preparation of your testimony in the period of time between the engagement and the service of your testimony, do you think it would make more sense for Mr. Holter to be the testifying witness on some of these issues than you?

A I have no idea. I don't know what his expertise is. And I don't know that he actually wrote the testimony. He could have just opened the file on 10-19 or 11-19 or whenever it was created. I guess it was created sometime around 9-23 maybe.

Q And --

A Hard to tell.

Q And if he just opened the document, then that would mean Mr. Gruen drafted the testimony based on this metadata; is that correct?

A No, not --

I mean, metadata, this only goes to this electronic file; so the file could be saved as another document, as a new document. You could start over.

I don't -- I don't know that you can really glean a whole lot by this particular metadata.

Q Ms. Felts, with respect to your portion of the testimony, which is related to the recordkeeping

violations --

MR. GRUEN: Objection. That's a mischaracterization of testimony.

She has identified that she is sponsoring the whole -- the entirety of the testimony, not just recordkeeping.

MR. STODDARD: I'm sorry, let me correct that.

Q With respect to the portion of the testimony that you wrote, which relates to the recordkeeping violations, Ms. Felts, what is your experience with recordkeeping practices at gas storage fields?

A Only that I reviewed records for the Playa del Rey and the Montebello cases.

Q So you haven't looked at recordkeeping practices at other gas storage fields?

A No. I only looked at the recordkeeping entries in the PG&E records retention documents. I think I provide those to you in response to a data request.

Q And aside from that, nothing else?

A No.

MR. STODDARD: Okay. I think that's it.

THE WITNESS: Do you want to redirect?

MR. GRUEN: I just want to be sure.

MR. STODDARD: Apologies.

One more document.
MR. GRUEN: Okay.
(Deposition Exhibit 1-35 was marked for identification and is attached hereto.)
MR. STODDARD: Mark this as Exhibit 1-35.
Q Ms. Felts, do you recognize this document?
A I don't think I've seen this document.
Q You did indicate that you accessed the Commission's Aliso Canyon Web page, correct, but you had trouble downloading a Blade report from there, I think?
A Yes.
Q Do you see down about three-quarters of the way down the page --
A Okay.
Q -- where it says "Both the Division," I guess at the bottom, both "The Division and the PUC have directed the Gas Company to hire an independent third party to perform a technical root cause analysis of the well failure"?
A Yes.
Q Is it your understanding from your review that Blade's investigation has been fully independent?

A Yes.
Q Turning to Appendix B, do you see on page 1 the "Findings and Timeline"?
A Yes.
Q Do you see there in the first sentence of last paragraph where it states "SED will release its official investigation report upon completion of all aspects of its investigation"?
A Yes.
Q And to confirm, you're not aware of any such official investigation report; is that correct?
A Wasn't -- doesn't --
Isn't that related to the Blade report?
Q This is SED's report.
A Okay. I guess I misread that.
Q Are you aware of an SED official investigation report?
A No.
Q Okay.
MR. GRUEN: I just note a foundation objection for the record.
She has noted that she hasn't seen this document before, she doesn't recognize it.
But the questions are noted.
MR. STODDARD: All right. That's it.

MR. GRUEN: Okay.
MR. STODDARD: Go off the record?
MR. GRUEN: Yeah.
MR. STODDARD: Do you have any other comments?
MR. GRUEN: Yeah. I'll wait until we're off.
THE VIDEOGRAPHER: We are off the record at 8:27 p.m.
(Off the record.)
THE VIDEOGRAPHER: We are back on the record at 8:31 p.m.
MR. GRUEN: While we were off the record, SoCalGas and SED agreed that Ms. Felts can offer a clarification statement for her earlier testimony today. And if so SoCalGas wants to ask follow-up questions on that statement, SED has no objection.
Go ahead.
THE WITNESS: Okay. Do you want me to just say what it is?
MR. GRUEN: Yeah.
THE WITNESS: That one?
MR. GRUEN: Yeah.
THE WITNESS: Well, so you asked me about my contractor license earlier, and I looked it up, and it is called -- in California it's called an a general engineering contractor license.

So when I said general engineering license, I think maybe I misspoke and didn't add the "contractor" on. But somehow it was misunderstood. I just wanted to clarify that.

I have put that on inactive, and apparently in the last couple of years privacy must have gotten to the contractor -- the state license board because you can no longer look it up under my name if it's inactive; So some old -- an old license number when I was incorporated comes up under Invictus as not -- not inactive, but it's actually a dead license.

The current one that is inactive, I would have to provide you the license number, and I don't have it with me. But I could do that if you want it. And then I think it will come up maybe.

MR. STODDARD: Okay.

THE WITNESS: But I think I could get those records if you needed them.

MR. STODDARD: Yes, we would appreciate that.

Well, actually let me ask one quick question.

Q What is the purpose of the general engineering contractor's license?

A It's basically the top tier of general contractors license. It basically gives me license

in California to do any kind of construction on contracts.

Q And to subcontract?

A And subcontract. So a general --

Like if you go hire a general contractor to build a building, that would be me. Then I subcontract all of the work out and handle all of the permits and oversight; so it is a major category. It's the category if you want to be into construction.

I acquired it early on to be able to drill wells for groundwater monitoring and to be able to do hazardous waste cleanup. I did have to take an additional exam for the hazardous part of it; so mine says "A General Engineering Contractor-HAZ," which means I'm allowed to manage site cleanups where there is hazardous waste.

Q Okay. Yes, I think we would like to see copies of that --

A Okay.

Q -- license.

And just to reiterate, because I was confused about this earlier, but -- and I want to make sure I have it clear, and I apologize if I already asked this question.

Do you have any other engineering-related licenses or certifications or credentials?

MR. GRUEN: That she hasn't already identified in the course of the deposition today?

MR. STODDARD: Well, I just want to be clear that we're not --

I might be confused.

For sake of the record, we now have established and I understand the general engineering contractor's license.

Q Are there any others?

A No.

MR. STODDARD: Okay.

MR. MOSHFEGH: Confirm for one --

MR. STODDARD: Sure.

I don't think we necessarily need to. I --

Housekeeping item for purposes of the record.

We've noted that you've objected today to questions related to Ms. Felts' work since the service of opening testimony?

MR. GRUEN: Right.

MR. STODDARD: We don't -- we don't have those documents. Sounds like there might be additional work product being generated at this time; we don't

have access to that.

We are going to see her live testimony at some point in time, which presumably will be based on that work product and given that that's basis of the objection, so, procedurally, we would like to keep the deposition open, and the request for work papers in particular open so that after the next round of testimony is served, you would then produce to us any additional work papers.

MR. GRUEN: I think it's appropriate for a second -- if you want to produce --

If you want a deposition that is based on, then it's appropriate to do a new round.

This was understood to be a notice of deposition related to opening testimony. You know, you're entitled to propound discovery.

MR. STODDARD: We can notice a new deposition with the understanding that this is -- you know, it would be based on that objection, essentially.

MR. GRUEN: Yeah. And, you know, we'll bear it in mind.

But I will say, Jack, we're -- the timelines grow tighter. We're noting that the reply testimony is due February 21st, rebuttal is the 27th of March. The ability for us, with our limited bandwidth, to

juggle that additional deposition time with the ability to prepare testimony and do discovery is getting harder; so we just ask that you bear that in mind.

But we understand the request and if you want to request the -- we anticipate that you may want to request the work papers associated with future testimony as well. And we'll bear that in mind and work to cooperate on that discovery along those lines.

MR. STODDARD: Yeah.

Just to be clear, we wouldn't be requesting a deposition prior to your service of testimony --

MR. GRUEN: Understood. We appreciate that. Yeah. Okay.

MR. STODDARD: -- unless we get new information related to her testimony that wasn't produced today that you produce at a later date that is relevant to -- right, with that one caveat in mind.

But assuming when we're talking about the work papers for purposes of the reply testimony, our reservation for an additional deposition would be after the service of the reply testimony.

MR. GRUEN: And we have the same concern with rebuttal, of course, that immediately before rebuttal

testimony, we'll be busy in preparing that as well, the March 27th testimony.

MR. STODDARD: Right.

MR. GRUEN: Okay. Sounds like we can work that out okay.

MR. STODDARD: Anything further?

MR. GRUEN: Nothing further from SED.

Thank you.

THE VIDEOGRAPHER: This is the end of our deposition, the end of disk number five, Volume number 1, of the deposition of Margaret Felts on February 5th of the year 2020.

We are off the record at 8:39 p.m.

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REPORTER'S DEPOSITION TIME LOG:

REPORTER - LINDA SILVER RYAN

DATE - Wednesday, February 5, 2020, 2019

WITNESS - MARGARET FELTS

ATTORNEY	ON RECORD	OFF RECORD	TOTAL
STODDARD	9:23 A.M.	10:55 A.M.	1:32
	11:13 A.M.	12:15 P.M.	1:02
	1:24 P.M.	2:30 P.M.	1:06
	2:47 P.M.	3:39 P.M.	0:52
	3:44 P.M.	3:52 P.M.	0:08
	4:25 P.M.	5:59 P.M.	1:34
	6:22 P.M.	7:42 P.M.	6:03
	8:06 P.M.	8:27 P.M.	0:21
	8:31 P.M.	8:39 P.M.	0:08
		TOTAL USED:	9:04

CHANGES AND SIGNATURE

WITNESS: MARGARET FELTS

DATE OF DEPOSITION: Wednesday, February 5, 2020

PAGE	LINE	CHANGE	REASON

STATE OF _____)
) Ss.
COUNTY OF _____)

I, the undersigned, say that I have read the foregoing deposition, and I declare, under penalty of perjury under the laws of the State of _____, that the foregoing is a true and correct transcript of my testimony contained therein, incorporating any and all changes and/or corrections as heretofore noted by me, and the reasons for same.

EXECUTED this _____ day of _____, 2020, at _____.

_____
MARGARET FELTS

I, the undersigned, a Certified Shorthand Reporter of the State of California, do hereby certify:

That the foregoing proceedings were taken before me at the time and place herein set forth;

That any witnesses in the foregoing proceedings, prior to testifying, were placed under oath;

That a verbatim record of the proceedings was made by me using machine shorthand which was thereafter transcribed under my direction;

That the foregoing deposition is a full, true and correct transcript of my shorthand notes so taken and transcribed;

That any dismantling of this transcript will void my certification as a Certified Shorthand Reporter;

I further certify that I am neither financially interested in the action nor a relative or employee of any attorney of any of the parties.

IN WITNESS WHEREOF, I have this date subscribed my name.

Dated: _____

_____

LINDA SILVER RYAN

CSR No. 9915

A

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Ex. I - 11

Pressure Equipment Integrity Incident Investigation

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Pressure Equipment Integrity Incident Investigation

1 Scope

1.1 General

The purpose of this document is to provide owners/users with practices for developing, implementing, sustaining, and enhancing an investigation program for pressure equipment integrity (PEI) incidents. This recommended practice (RP) describes characteristics of how an effective investigation could be structured so organizations can learn from PEI incidents. This RP is not intended to define or supplement criteria for compliance with regulatory requirements for which companies already have defined investigation processes in place. Rather, API 585 provides a specific focus on investigating PEI failures that are precursors to potential incidents that could have significant impact on safety, health, and environment.

Significant mechanical integrity incidents are rarely the result of one isolated issue; there are almost always less severe precursors to a major failure. These precursors are frequently called near misses when they are found. Additionally, this document highlights the value in recognizing these precursor occurrences and promotes investigating them to determine the immediate, contributing, and root causes. If these precursor occurrences are uncovered, investigated, and the contributing and root causes are resolved, then major catastrophic failures of pressure equipment could be minimized or prevented.

1.2 Industry Scope

The investigation principles and concepts that are presented in this RP are specifically targeted for application to process pressure equipment in the refining and petrochemical industry but could be applied to other equipment at the discretion of the owner/user.

1.3 Flexibility in Application

Because of the broad diversity in organizations' size, culture, national, and/or local regulatory requirements, API 585 offers users the flexibility to apply the investigation methodology within the context of existing incident investigation practices and to accommodate unique local circumstances. API 585 is intended to promote the use of systematic investigations as a way to learn from unexpected leaks and equipment degradation or near misses associated with PEI.

Investigation methodologies consist of investigators collecting evidence and conducting an analysis of the evidence to determine the causes. Many types of investigation analysis methods exist and are used throughout the industry. This document is not intended to single out one specific analysis method for conducting investigations. This document highlights PEI issues for investigation and provides guidelines and work processes for PEI incident investigations.

1.4 Pressure Equipment Integrity (PEI) Focused

Investigation is a vital element for learning from unexpected discoveries or incidents (e.g. finding significantly more corrosion damage or other forms of deterioration than expected) and can be used in a continuous improvement process. Investigating and determining the causes of unexpected leaks, equipment degradation, or near misses associated with pressure equipment may be used to improve mechanical integrity programs and management systems for maintaining PEI, such as design and construction procedures, maintenance and inspection practices, and operating practices.

The Inspection, Corrosion/Materials, and Storage Tank Subcommittees of the API Committee on Refinery Equipment have produced a variety of codes and standards to guide owners/users in maintaining pressure equipment integrity and reliability, a listing is included in the Bibliography for reference.

1.5 Types of Pressure Equipment Covered

The following examples are the types of equipment considered to be within the scope of this document.

a) Pressure vessels—all pressure-containing components.

b) Piping—pipe and piping components (valves, expansion joints, sight glasses).

c) Storage tanks—atmospheric, low pressure, and pressurized.

d) Rotating equipment—pump and compressor cases and associated pressure-containing piping and pressure vessels, excluding seals.

e) Boilers and heaters—pressurized components.

f) Heat exchangers—shells, heads, channels, and pressure-containing components and tube bundles.

g) Pressure-relief devices.

h) Structural systems—integral to supporting pressure-containing systems.

i) Cooling water towers.

j) Stacks and flares.

Other types of pressure equipment can be included at the discretion of the owner/user.

1.6 Types of Equipment Excluded

The following nonpressurized equipment is not intended to be covered by this RP but could be included at the discretion of the owner/user.

a) Instrument and control systems.

b) Electrical systems.

c) Machinery components (except pump and compressor pressure-containing cases).

d) Structural equipment not associated with a pressure-containing component or system.

e) Pressure vessels or piping systems on movable structures, including piping systems on trucks, ships, barges, and other mobile equipment.

1.7 Target Audience

The primary audience for API 585 is the inspection and engineering personnel working in the PEI programs within refineries and petrochemical plants. However, investigations often require the involvement of various segments of the organization, such as engineering, maintenance, inspection, operations, and supervision. Corrective action and recommendations to address the causes may rest with more than one segment of the organization. Therefore, while the primary audience may be PEI personnel, it is suggested others within the organization who are likely to be involved become familiar with the concepts and principles embodied in this RP.

1.8 Organizational Responsibilities

Owners/users can incorporate PEI investigation into a broader incident investigation site program or develop a specific PEI incident investigation procedure that includes guidance provided in this document including roles, responsibilities, protocols, and specific activities to be carried out by site personnel in the process of implementing this RP. Management demonstrates its commitment to this RP by allocating resources and assigning responsibilities to support the PEI incident investigation system.

2 Normative References

The following referenced document is indispensable for the application of this document. The latest edition of the referenced document (including any amendments) applies.

API Recommended Practice 571, *Damage Mechanisms Affecting Fixed Equipment in the Refining Industry*

3 Terms, Definitions, Acronyms, and Abbreviations

3.1 Terms and Definitions

For the purposes of this document, the following terms and definitions apply.

3.1.1
bias
When people or groups use their past experience or judgment to direct the evidence gathering and development of causes towards potentially incorrect conclusions or when investigators predetermine the cause of an incident and then look for confirming evidence and disregard disputing evidence.

3.1.2
chronic incidents
Frequent occurrences, especially when each occurrence alone typically has a low or minor consequence and is routine to fix.

NOTE Chronic incidents may happen routinely and may become expected and planned.

3.1.3
consequence
An undesirable outcome from an incident. There may be one or more consequences from an incident for different categories, such as safety, environmental, and/or economic. Consequences are always negative for integrity incident investigations.

3.1.4
contributing cause
A cause that increases the likelihood and/or consequence of an incident but is not the immediate or root cause. Eliminating the contributing cause will not by itself prevent reoccurrence but will likely reduce the frequency and/or consequence of any reoccurrence.

EXAMPLE An example of a contributing cause for a failure caused by corrosion under insulation (CUI) might be: the plant has poor maintenance practices for maintaining coatings, insulation, and jacketing.

3.1.5
immediate cause
The most direct or primary contributor to the incident that if eliminated or avoided would have prevented the incident. Also known as the physical cause or direct cause.

EXAMPLE For a carbon steel pipe segment that developed a hole and leaked process fluid, the immediate cause was determined to be acid that unexpectedly came in contact with the carbon steel pipe and caused the pipe to corrode at an accelerated rate.

3.1.6
integrity operating window
IOW
Established limits for process variables (parameters) that can affect the integrity of the equipment if the process operation deviates from the established limits for a predetermined amount of time. Reference API 584 (pending publication) for more information regarding IOWs.

3.1.7
investigation
The process of identifying the immediate, contributing, and root causes of incidents (failures and near misses) and developing recommendations to prevent similar occurrences.

3.1.8
investigator
The person or group that conducts the investigation by collecting the evidence, analyzing the evidence, determining the causes, and making recommendations.

3.1.9
owner/user
An owner or user of pressure equipment who exercises control over the operation, engineering, maintenance, inspection, repair, and testing of the pressure equipment.

3.1.10
pressure equipment integrity
PEI
mechanical integrity
The state of pressure equipment when it has been and continues to be designed, fabricated, installed, operated, and maintained in a way to prevent loss of containment or loss of structural stability.

3.1.11
pressure equipment integrity failure
PEI failure
The termination of the ability of a pressure equipment system, structure, or component to perform its function of containment of the process fluid (i.e. a leak or loss of containment). Loss of containment due to misoperation of equipment and not involving material damage mechanisms is not considered PEI failure for the purpose of this RP. Within this document, the term "failure" is intended to refer to a PEI failure.

3.1.12
pressure equipment integrity incident
PEI incident
A PEI failure or a PEI near miss. Within this document, the use of the term "incident" is intended to refer to a PEI incident.

3.1.13
pressure equipment integrity near miss
PEI near miss
The discovery of equipment degradation or process operating conditions outside of acceptable limits that requires immediate action to shut down the equipment and/or perform repairs to avoid a loss of containment, usually the result of some form of damage mechanism such as those covered in API 571, but did NOT result in a loss of containment or structural stability. Within this document, the term "near miss" is intended to refer to a PEI near miss.

3.1.14
pressure equipment integrity personnel
PEI personnel
Personnel in an organization assigned to maintaining, developing, improving, and implementing the organization's PEI program.

EXAMPLE Positions or job titles such as inspector, authorized inspector, inspection engineer, inspection supervisor, pressure equipment engineer, piping engineer, reliability engineer, storage tank engineer, corrosion specialist, metallurgist, etc.

3.1.15
probable cause
If, after thorough analysis of the evidence and facts, a cause cannot be fully proven but is determined to be very likely (more likely than not), then it is called a probable cause. A probable cause can be identified in any of the different causes (immediate, contributing, or root).

3.1.16
process safety incident
An incident that resulted in, or could reasonably have resulted in, a catastrophic release of highly hazardous chemicals in the workplace as defined by the Occupational Safety and Health Administration's process safety management (PSM) regulation.

3.1.17
risk
Combination of the frequency of an incident and its consequence. In some situations, risk is used to describe a deviation from the expected. When frequency and consequence are expressed numerically, risk is the product.

3.1.18
root cause
A fundamental, underlying system or culture related reason why an incident occurred or allowed the immediate or contributing cause(s) to exist. There is often more than one root cause for every incident.

EXAMPLE An example of a root cause for a failure due to CUI might be: there is a culture of only reacting to problems and not allocating resources to preventative maintenance activities.

3.1.19
sporadic incident
An infrequent or very infrequent occurrence. These incidents tend to have an unusual combination of causes and could have a high consequence.

3.2 Acronyms and Abbreviations

For the purposes of this document, the following acronyms and abbreviations apply.

CUI	corrosion under insulation
DCS	distributed control system
FA	failure analysis
IOW	integrity operating window
NDE	nondestructive examination
PEI	pressure equipment integrity
P&ID	piping and instrument diagram

QA	quality assurance
QC	quality control
PSM	process safety management
RCA	root cause analysis
SME	subject-matter expert

4 PEI Incident Tracking

4.1 PEI Incident Types

PEI incidents are unexpected discoveries or occurrences relating to pressure equipment, usually involving loss of containment or the potential for loss of containment due to some form of damage mechanism such as those covered in API 571. This document will refer to both failures and near misses as PEI incidents throughout.

The following are some examples of the two different types of PEI incidents as they relate to pressure equipment.

a) Failures:

— flange leak of process fluid (not including environmental fugitive emissions leaks);

— equipment damaged from corrosion resulting in leak of process fluid;

— through-wall crack resulting in leak of process fluid;

— equipment rupture;

— structural failure (due to structural component deterioration or physical damage to the structure) resulting in pressure equipment leak or damage requiring repairs or rerating (e.g. deterioration of external support rings);

— a process pressure and/or temperature excursion or pH excursion resulting in loss of containment and/or damage to the process equipment requiring repairs;

— heat exchanger tube bundle leak or rupture causing a loss of primary containment (e.g. air cooler tube leak or a tube bundle leak into a cooling water system with detectable emissions to atmosphere at the cooling tower). For the purpose of this RP a tube failure that does not result in a loss of containment is not considered a failure.

b) Near misses:

— discovery of corrosion or other damage/degradation that does not pass a Fitness-For-Service assessment and requires immediate repair, but did not result in a leak;

— discovery of a damaged bolt or gasket that requires immediate repair, but before any failure or leak occurred;

— structural deterioration that is found and deemed not fit for service (e.g. during potential wind loading), but before a structural failure occurred;

— process chemistry or other operating condition that is found to be outside of an acceptable process integrity operating window (IOW) for corrosion or other material degradation mechanism and requires immediate inspection or repair, but before failure or leak occurred;

— inspection or testing failure of a pressure-relieving device indicating that it would not have protected the equipment during an overpressure incident, but there was no incident that resulted in an overpressure or equipment failure;

— discovery of a compromised overpressure protection device (such as a closed block valve in the relief path or the wrong relief valve installed with a higher cold differential test pressure setting), but there was no incident that resulted in overpressure or equipment failure;

— discovery of significantly more damage than expected upon a routine inspection;

— discovery of the wrong metallurgical component installed, but before any significant damage or failure occurred;

— discovery of the wrong specification piping or fitting installed, but before any failure occurred (e.g. wrong schedule nipples installed);

— discovery of the wrong gaskets or bolting being installed, but before being put in service or before there was a leak.

Failures may be known or detected at the instant of occurrence (announced failure) or undetected at the instant of occurrence (unannounced failure). For example, a rupture of a pipe in a process plant or sudden decrease in pressure in the system is likely to be detected at the instant of occurrence and would be an announced failure. Examples of unannounced failures include a slow leak under insulation that may not be detected until a pool of fluid forms on the ground or someone notices a drip or wisp of vapor, or a slow leak from buried piping or small leak in a heat exchanger tube that may not be noticed until the next inspection.

PEI incidents differ in the typical frequency of occurrence (chronic or sporadic) and the severity or consequence of the outcome. A chronic incident typically has ongoing common cause(s) that result in recurrence of the same or similar type of outcome over time. Examples of chronic incidents include reoccurring flange leaks, continuing discovery of CUI damage throughout a plant, multiple instances of finding the wrong specification material or bolting during final inspection, and multiple cases of finding the wrong schedule piping installed as nipples. Sporadic incidents tend to have an unusual combination of causes that result in an outcome of a certain type very infrequently or possibly only once in the life cycle of the pressure equipment. Any of the items listed previously under failures could be considered a sporadic incident. Valuable lessons can be learned from investigating both chronic and sporadic incidents, regardless of the outcomes.

4.2 Documenting PEI Incidents

PEI incidents, even low-consequence incidents, provide opportunities to learn through investigation in order to identify the causes and implement improvements to prevent a potential major failure. PEI personnel should report incidents discovered in pressure equipment, including unexpected discoveries during inspections or monitoring of process operations. The tracking of PEI incident data provides opportunity to identify trends and improve PEI.

The reporting of PEI incidents should be done in a consistent manner and tracked so that the data can be more easily reviewed and analyzed. Annex A is an example of an incident reporting form that may be useful for such purpose. An incident report should be documented within a short period of time after the incident is recognized. The incident document should be reviewed to determine if an investigation is warranted. If trends are identified or suspected then that grouping of PEI incidents can be investigated further to determine underlying common systemic causes. For example, it may be appropriate to investigate a grouping of chronic incidents (e.g. several instances of the wrong gasket being installed or several instances of a minor flange leak on a feed/effluent exchanger during start-up). Reporting could be computerized to facilitate analysis for systemic causes and to improve the ability to steward follow-up items to closure.

One way to implement this work process is to select a certain frequency, such as annually, to review reported PEI incidents to look for indications of common causes or similarities. The incidents that are similar or might have common causes could then be investigated as a group. The level of investigation used should be defined in the owner's/user's investigation classification system. The consequence used for classifying a grouping of incidents might be the sum of the individual consequences for each incident.

Investigation findings and results may be recorded in a standardized format such as those shown in Annex C and Annex G. This will help in collecting relevant data and enable trending of causes to look for common risk factors or common causes that reoccur over time so that more extensive development of corrective actions or PEI work process improvements can be identified.

5 PEI Incident Causes

5.1 Types of Causes

PEI incidents are usually the result of multiple causes and may be categorized into different types. One particular way to categorize causes is into the following three different types:

1) immediate causes,

2) contributing causes,

3) root causes.

These causes are shown in the order of increasing depth of analysis:

1) identifying and correcting the immediate or physical causes of an incident will only prevent an identical incident from occurring again on the same equipment, same type of equipment, or other equipment in the same part of the process;

2) identifying and correcting the contributing causes goes further in reducing the likelihood of future similar PEI incidents on other equipment throughout the process or facility;

3) identifying and correcting the root causes will result in improved PEI management systems and work culture and should prevent or reduce the likelihood of many other PEI incidents from occurring throughout the facility or company.

An effective investigation will determine not only the immediate cause of the incident but also the contributing causes and root causes. Root causes are typically related to management systems or organizational cultural issues that need to be corrected to prevent other incidents from occurring.

Conducting investigations and utilizing a structured root cause analysis (RCA) methodology to determine the systems related causes will often reveal that there are multiple underlying causes. Most investigations can determine many of the contributing causes. Determination of the true root causes of an incident takes a thorough investigation conducted by trained and experienced personnel and is generally best accomplished with a Level 3 investigation, described in 5.2.

Any of the three types of causes (immediate, contributing, and root) can also include a probable cause. If, after thorough analysis, some causes cannot be fully proven but are determined to be the most likely causes, then these are called probable causes. The investigation team, along with the investigation sponsor, should review these probable causes to assure they are based on sound reasoning and some evidence and not personal bias. Bias can be the result of intentional or unintentional predetermination of causes.

An example to illustrate the three types of causes is as follows from this fictitious situation. A carbon steel pipe in a sulfuric acid alkylation unit failed and released alkylate. After a PEI incident investigation, it was determined the loss of containment causes were the following.

a) Immediate cause: the loss of containment occurred because sulfuric acid came in contact with the carbon steel pipe and rapidly corroded it to the point of failure.

b) Contributing causes:

— there are inadequate operating controls to prevent acid carryover in the process,

— operators did not recognize and properly react to the abnormal operating condition that caused the acid carryover.

c) Probable root causes:

— leadership did not adequately address the lack of controls on process operations,

— rigorous training of operators and retraining is not considered important to site management.

5.2 Determining Causes

Determination of causes of an incident should be based on a systematic analysis of the evidence and facts collected. During the course of the investigation, the team will determine what happened leading up to the incident and the causes. There are intermediate analysis steps to prove or disprove theories of causes. Systematic analysis of evidence and use of fact-based reasoning are usually sufficient to prove or disprove cause theories. This RP describes three levels of PEI incident investigations.

1) Level 1 is a simple one- or two-person investigation on low-consequence PEI incidents that can be done in a fairly short period of time. Level 1 uses the evidence and the judgment and experience of the investigator to determine the causes.

2) Level 2 is a more thorough investigation of medium-consequence PEI incidents that normally involves a small team and takes a bit more time to gather and analyze evidence and determine causes. The team may use casual factor or logic tree analysis techniques to determine the causes.

3) Level 3 is a more detailed investigation of high-consequence PEI incidents that involves a team typically led by a trained/experienced root cause investigator. Level 3 investigations involve the gathering of much more evidence and conducting in-depth analysis and may take several weeks to complete. Level 3 should use a structured RCA methodology to determine the three types of causes.

All three levels of investigation are designed and intended to identify the immediate and contributing causes, but Level 2 or Level 3 investigations may be required to uncover the root causes of the incident.

Each investigation, at any level, should determine the exact immediate cause of the incident, based on evidence. If the immediate cause cannot be determined, then the team or investigator should look for more evidence or consult with additional expertise or request a metallurgical failure analysis (FA). Typically, when the immediate cause cannot be determined, it means that some key evidence has been missed or is missing. If, after gathering more evidence or additional review of the evidence, the immediate cause can still not be determined, then the most probable immediate cause of the incident should be defined and clearly documented, with both the known facts and assumptions identified.

Two of the main differences between the investigation levels are in the depth of the investigation and the precision used in determining the contributing and root causes. For the Level 1 investigation, the investigator's best knowledge of the organization and systems is used to identify the probable causes. For a Level 1 investigation, the identified

causes may not be true root causes based on detailed analysis of evidence but are people's opinion based on their experiences of the cultural and systemic issues within the organization. It is important to document these causes, even if they are not precise, so that ideas can be collected and grouped with other Level 1 investigations to determine any trends in probable contributing and possible root causes. If enough Level 1 investigations are conducted and the identified probable and possible causes are grouped, this will most likely identify real systemic or cultural issues that could then be addressed to determine corrective actions.

The Level 2 investigations should be able to determine the immediate causes, contributing causes, and probable root causes of the incident based on analysis of the evidence and agreement between the team and the investigation sponsor. The Level 2 investigation may not determine all the root causes because of factors such as the experience of the investigation team and the depth of analysis. Identifying corrective actions for the causes that are identified and agreed to by the team and the investigation sponsor should help to prevent future incidents from occurring.

As discussed, because of the brevity or simplicity, Level 1 or Level 2 investigations may not be able to precisely define or prove all of the contributing and root causes. Based on the evidence and analysis, consideration should be given to making recommendations based on the probable causes to best mitigate the potential for additional incidents.

The Level 3 investigations are typically led by trained and experienced RCA personnel and are thorough enough to identify all of the causes of the incident, including the root causes. Level 3 investigations will often be driven by others outside of the PEI organization and either within or outside the site organization.

6 PEI Incident Investigations

6.1 General

It is impractical and unnecessary to investigate every PEI incident to the same level of detail. As indicated in the foregoing, there are different degrees of consequence and complexity of incidents, warranting different levels of investigations. Generally, the more serious or potentially serious an incident, the greater the scope and depth the investigation would be. Every PEI incident could be reviewed to determine if an investigation is warranted and what level of investigation is appropriate. The consequences of the incident, both actual and potential, are typically used to determine the level of the investigation. When using potential consequences as a deciding factor in determining level of investigation, care should be taken to use only the most likely scenarios that might have occurred if one or possibly two other events had happened, but not more than two. The assumptions used for determining potential consequences should be clearly documented and agreed upon with the investigation sponsor.

EXAMPLE 1 If a leak occurs and releases gasoline that forms a vapor cloud but does not cause a fire or explosion because an operator immediately saw the leak and turned on fire monitors, then it is reasonable to consider fire and explosion as a potential consequence and investigate based on that.

EXAMPLE 2 If a leak releases diesel and a small pool fire results that is contained by the emergency response, it might not be reasonable to say that the potential consequence would have been major equipment damage if the fire monitors were not working and the emergency shutdown valves had not been activated.

The three levels of investigation described in this RP differ in scope and depth of investigation and the amount and type of personnel involved. Owners/users may provide guidelines defining the different levels of investigations and the circumstances under which they are used. Table 1 is an example of defining the guidelines for PEI incident investigations. The guidelines herein will define the differences in the levels of investigation. These differences are mainly based on the personnel that are involved, including the qualifications and number of those personnel, the depth of analysis, the reporting requirements, and the follow-up.

6.2 PEI Incident Investigation Levels

For the purpose of this RP, the highest level investigation, Level 3, would be performed when a single PEI incident has a large actual or potential consequence. A Level 2 investigation would be performed on a single PEI incident that had a medium actual or potential consequence. A Level 2 investigation could also be conducted on a grouping of similar chronic PEI incidents that, when combined, have a medium actual or potential consequence. A Level 1

investigation would be performed on low-consequence PEI incidents. These Level 1 investigations are opportunities to learn and act on small incidents and proactively prevent similar chronic incidents or future larger incidents.

Typically, the level of investigation is independent of the type of incident but is determined by the consequence or potential consequence of the incident. For example, pressure equipment failures, depending on the consequence and/or specifics, might have a Level 1, Level 2, or Level 3 investigation conducted. The starting point for near misses is usually a Level 1 or Level 2 investigation.

The following are examples of some specific PEI incidents that might warrant a Level 1 investigation:

— incorrect gasket installed and leaked without causing a fire;

— short-term corrosion rate discovered to have doubled over long-term rate;

— incorrect alloy discovered in valve before it was installed;

— Schedule 40 nipple installed where Schedule 80 required in piping specification;

— small-bore piping threaded connection installed directly adjacent to a vibrating reciprocating compressor;

— inspector discovers B7 bolting installed on exchanger floating head where specification called for B7M in sour service;

— inspector discovers wrong weld rod being used by welder for Cr-Mo piping replacement;

— inspector discovers utility hose being used for process drain hose;

— thermography inspection finds 50° hot spot on radiant tube;

— small underground leak discovered in Class 2 buried piping.

The following are examples of some specific PEI incidents that might warrant a Level 2 investigation:

— high-pressure boiler tube rupture;

— storage tank bottom leak;

— inspection finds a process pipe in operation below minimum required thickness;

— a feed/effluent heat exchanger flange leaks on start-up and causes a small hydrogen flame;

— a process heater tube ruptures causing furnace fire that is blocked in and snuffed out without significant damage to the firebox;

— a relief valve opens prematurely, releasing a few hundred pounds of product before being blocked in;

— a relief valve is discovered to be plugged during servicing;

— piping vibration near a reciprocating compressor causes fatigue crack and product release requiring compressor station to be blocked in and taken off line;

— a heat exchanger tube rupture causes heat exchanger to be blocked in and taken off line for inspection and repairs;

— CUI leak causes side-stripper column to be blocked in and taken off line for repair;

— a gasket blows out on a blocked-in product line releasing a few hundred gallons of hazardous fluid;

— pinhole leak develops on a hydrocarbon process line and ignites, but an operator is able to extinguish it and block it in, before major damage.

6.3 PEI Incident Investigation Guidelines

Owners/users may develop investigation guidelines that define what consequences and what types of failures or near misses trigger what level of PEI incident investigation. The guidelines typically include the combinations of actual and potential consequences and frequency of occurrence for the different levels of investigation.

The investigation guidelines include the following:

a) examples of incident types and consequences for each;

b) team leadership, team size, and composition;

c) timing for investigation initiation;

d) management level of sponsorship.

Table 1 is an example of an investigation guideline for PEI type incidents and specifically does not define investigation characteristics, team makeup, or timing requirements for any particular regulatory requirement.

6.4 Initial Response to a PEI Incident

The owner/user may have a documented plan on how to promptly respond to PEI incidents so that the need for investigations can be quickly recognized and initiated. This may be developed at the facility level or at a company level. The level of investigation and the timing of initiating the investigation may also be prescribed by governing jurisdictions, which is outside the scope of this RP.

This RP is not intended to detail the emergency response or internal and external notifications. (For example purposes, the company should designate who should be notified immediately to determine the need to notify regulatory and insurance representatives, if necessary.)

As previously noted, the facility or company may have a written process that defines how information from PEI incidents could be reviewed to determine if an investigation is warranted and how it is initiated. When an incident occurs, it is important to begin collecting data and evidence as soon as safely possible. If collecting of data and evidence is not initiated immediately, some valuable information might be lost in repair and cleanup activities. The most serious or highest consequence PEI incidents should have evidence gathering started soon as practical after it occurs. It is important that accurate data on PEI incidents is collected so that those incidents can be properly tracked and reviewed to determine the causes and corrective action.

The facility may have a work process to assign an investigation leader and team members immediately after a high- or medium-consequence incident is recognized (the incident may still be ongoing while the investigation team is identified and assigned). For PEI incidents that require emergency response, the lead investigator might be available to begin the gathering of physical evidence as soon as the area is secured by the emergency response team and released by regulatory authorities, if they are involved. If the lead investigator is not immediately assigned or available, then PEI personnel who have been trained in proper gathering of evidence may begin the evidence gathering, or at least taking steps to preserve the evidence.

For PEI incidents that do not require emergency response, the supervisor or PEI personnel closest to the equipment could begin collecting information as soon as the issue is recognized. Annex A is an example of a form that can be used to collect the initial information. Once the information is collected, it could be reviewed by the appropriate manager or supervisor to determine if an investigation is warranted and the appropriate level of investigation.

Table 1—Example PEI Incident Investigation Guidelines

	Level 1 Investigations	Level 2 Investigations	Level 3 Investigations
Incident Characteristics	— Unexpected condition or damage found that if it had been allowed to progress would have led to loss of containment before the next scheduled outage or inspection interval. — Discovered PEI damage significantly beyond expectation but with no loss of containment or unit shutdown. — Small leaks (other than environmental fugitive emissions) from pressure equipment or joints that were easily contained. — Typically no fire, significant toxic release, injuries, or environmental damage would occur in a Level 1 incident.	— Leak from pressure equipment that resulted in or could have resulted in localized equipment damage, small to medium size release quantity, or small safety or environmental damage. — Unexpected pressure equipment failure from damage mechanisms or structural deterioration. — Unexpected pressure equipment damage or associated structural damage discovered that required equipment or unit shut down or immediate mitigation. — Repetitive Level 1 type characteristics in the same process or system.	Leak or rupture from pressure equipment that resulted in or could have resulted in significant process safety incident or environmental damage, equipment damage, large release quantity, or production loss.
Investigation Characteristics	Investigate using less structured analysis tools such as "What If" or "5-Whys." Uses evidence, judgment, and experience to identify causes.	Investigate using company or department causal factor identification or logic trees, seeking probable contributing and root causes.	Investigate using company structured root cause analysis (RCA) seeking to determine the deepest management system and cultural causes.
Team Makeup Recommended	Investigated by the PEI personnel from the affected area and trained in simple investigation techniques. Can be investigated by one person, possibly two. Involve subject-matter experts (SMEs) as needed.	Leader would be someone from the affected area trained in investigation techniques. Team members would include one to three others of different disciplines from the area; include at least one PEI person on the team. Involve SMEs as needed.	Leader would be someone trained in structured RCA and from another area of the plant or another business unit. There would be at least three team members and possibly from different disciplines or groups, such as inspection, operations, process engineering, maintenance, or process safety. Appropriate SMEs should be included on the team.
Initiation	Within a few days.	Begin investigation as soon as practical (e.g. 1 to 2 days).	Begin freezing and collecting evidence as soon as practical (e.g. within a few hours).
Sponsorship	Supervisor of investigator (First Line Supervisor).	Department Head level (Second Line Supervisor).	Management with overall responsibility for Safety Health Environment for the site.

6.5 Types of Evidence

There are three basic types of evidence that are used for investigating PEI incidents.

1) People—interviewing people involved in the incident, eyewitnesses, or those who have knowledge of the system, process, or equipment design as an example.

2) Physical—photographic documentation of as-found conditions, examination of the mechanical parts that are deficient or failed, any equipment involved in the incident, chemical samples (e.g. corrosion and fouling material), stains, damaged equipment, appearances and observations, physical sizing and orientation of

observed conditions, metallurgical analysis, secondary damage to surrounding equipment, valve positions, locations of fragments or debris, orientation of witness observations, and any other similar physical examples.

3) Records—paper and electronic records, including such items as operating logs, inspection records, prior engineering evaluations, design specifications, policies, procedures, alarm logs, test records, work orders and maintenance records, and training records. This would also include electronic format data, such as operating data recorded or correspondence (emails) pertaining to the system or equipment.

The three types of evidence listed above are in the order of what is typically the most time sensitive to be gathered before recollections or physical conditions or orientations can be changed or affected by bias. This can be used as a guide on what evidence to start collecting first (i.e. start performing eyewitness interviews as soon as possible after the incident, followed by physical evidence gathering). Note that some electronic operating records such as distributed control system (DCS) data disappear after a short specific time lapse, so data from those systems should be immediately preserved.

7 Conducting PEI Incident Investigations

7.1 General

This section provides general guidelines on how to perform the Level 1, Level 2, and Level 3 PEI incident investigations. For the purposes of these guidelines, the levels are as described in Table 1. Any PEI related incidents that are also process safety incidents may be governed by national regulations and/or jurisdictions having authority and should be handled by the appropriate group responsible for process safety incident investigations.

The main purpose of this section is to provide PEI personnel guidelines on how to conduct and support investigations. The CCPS's *Guidelines for Investigating Chemical Process Incidents*, 2003 [1] publication provides more detailed guidance on how to conduct investigations and could be used to build a comprehensive investigation program.

7.2 Performing Level 1 PEI Incident Investigations

7.2.1 General

Level 1 investigations are recommended for failures with minor actual or potential consequences, near misses, or unexpected discoveries concerning PEI. These investigations involve a review of the facts and identification of appropriate corrective action items. Level 1 investigations are less resource intensive than Level 2 and Level 3 investigations. When appropriate, Level 1 investigations identify specific corrective action items assigned to individuals with deadlines and periodic follow-up (e.g. unit inspector). The analysis is limited to localized incidents, and contributing causes and root causes are generally not evaluated in depth. The 5-Whys process is an example of an investigation method that may be used for Level 1 PEI incident investigations and is described further with an example in Annex B.

A Level 1 investigation might start with the incident report filled out with the knowledge about the incident that is known at the time of occurrence and a clear statement of the problem that is being investigated. Although no specific format for Level 1 investigations is prescribed in this RP, developing a form or guidelines for gathering and recording the information will be useful when reviewing these investigations for trends and further improvements.

7.2.2 PEI Level 1 Investigation Personnel

The Level 1 PEI incident investigation would be performed by one or two persons, typically the PEI personnel responsible for the equipment involved in the incident (e.g. inspector and/or engineer for the area where the PEI incident occurred). The following are guidelines on the type and role of personnel that could be involved in Level 1 investigations.

1) *PEI Incident Investigation Leader*—PEI personnel responsible for the equipment involved in the incident. If trained and qualified, the person could be the one who discovered the problem or the one who reported the incident.

   The investigation leader should have the training and knowledge to carry out the responsibilities for this level of investigation. This person may be the only one conducting the investigation and is responsible for collecting the evidence and analyzing the evidence in an unbiased way to determine the immediate, contributing, and possible root causes to the extent possible based on the evidence and facts. The investigation leader is then responsible for presenting the conclusions and recommendations to the sponsor for approval and endorsement. Finally the investigation leader is responsible for completing the final documentation.

2) *Team Members*—Typically, this level of investigation is performed by a single person. If another team member is needed, their training and qualifications would be dictated by the type of PEI incident that occurred and the need for assistance of the investigation leader. Others may be involved as needed to assist on an ad hoc basis by providing data/evidence, providing SME input, or being interview witnesses regarding the incident.

3) *Sponsor*—These investigations might be sponsored by the investigation leader's immediate supervisor or a supervisor/manager of the unit or department involved with the equipment where the incident occurred. The role of the sponsor is to ensure the investigator has the time and skills to complete and document the investigation and to set a date by which it needs to be complete. The sponsor would also help guide the investigator to ensure they are conducting an appropriate level of investigation and analysis. The sponsor would also have the responsibility to assure that follow-up corrective actions from the investigation were completed in a timely manner.

7.2.3 Collecting/Examining Evidence

The three forms of evidence—people, physical, and records—would be gathered or examined by the investigator(s).

The investigator would consider interviewing eyewitnesses (if there are any), people who work in the area, such as operators, process engineers, maintenance or reliability engineers, and any other PEI personnel involved with the equipment or incident. The investigator would collect and/or examine any physical evidence or parts involved or damaged in the incident. The investigator would examine any relevant documentation for the equipment or system, such as past inspection records, process operating history, design records, purchasing records, and maintenance or repair records.

If needed, the investigator could ask for expert help in the examination of some evidence or determining what additional evidence to examine.

7.2.4 Analyzing Evidence and Determining Causes

The investigator would analyze the evidence gathered and characterize what each piece of evidence is revealing about the causes of the incident.

The analysis includes looking at the evidence and determining, to the best of their ability, what the immediate, contributing, and possible root causes of the incident are. This may involve judgment and some subjective assessment. It is important to best determine the causes even if it is without 100 % certainty so that recommendations can be proposed for corrective actions to prevent a similar incident.

At times, it may be helpful if the investigator used a structured method, such as the 5-Whys, to determine the causes. In such cases, the investigator should be trained on the techniques or engage other knowledgeable experts. If the investigator cannot fully explain the immediate causes from the evidence gathered, they may need to gather more evidence or ask for additional SME expertise to help determine the immediate cause(s).

Level 1 investigations should identify the immediate causes of the incident. The investigation leader would also make a best effort at identifying contributing and possible root causes, based on the investigator's knowledge of the component failure mode or damage mechanism in conjunction with some specific information gathered about the

particular incident, and the investigator's knowledge of the facility's systems and work processes. Level 1 investigations are usually not rigorous enough to identify all of the contributing and root causes.

7.2.5 Action Items

The Level 1 investigation should include an understanding of the immediate cause to identify what actions need to be taken to address the immediate cause to prevent a similar incident. The investigator would also try to understand the contributing and possible root causes, with special emphasis on issues that represent opportunities for improvement that are within the control of the investigator or the control of the investigation sponsor. The investigator with approval from the investigation sponsor would recommend what action items are assigned and to whom.

With the focus on PEI incidents, consideration might be given to what changes may be needed to improve the PEI program to prevent similar incidents.

EXAMPLE Action items might include improvements on how inspection plans are developed or making improvements to the work process of how damage mechanisms are predicted and utilized in specifying on-stream nondestructive examination (NDE), or the investigation might reveal that additional process parameters should be monitored for IOWs.

7.2.6 Reports

Level 1 investigation results may be documented on a simple form or template such as that shown in Annex C. The report may document what happened, the immediate causes, the contributing causes, and the corrective actions. These reports are important for both the incident being investigated and to have quality information to review for trends and broader improvements.

7.2.7 Determining Effectiveness of Action Items

The identified contributing causes from many Level 1 investigations may be reviewed over time to look for common or systemic causes and to determine if they are being reduced and/or eliminated. If no improvement is shown, then this may be an indication that the follow-up actions were not effective. In such a case, a review may be conducted to determine how to more effectively address the reoccurring contributing causes or to identify additional contributing and/or root causes that should be addressed. This might involve a Level 2 investigation on a grouping of similar Level 1 incidents.

7.3 Performing Level 2 PEI Incident Investigations

7.3.1 General

Level 2 investigations are conducted on medium actual or potential consequence incidents (i.e. all that fall between Level 1 and Level 3). As previously discussed, the Level 2 processes may also be used to further analyze information from multiple, similar Level 1 investigations. Because Level 2 investigations typically involve higher risk incidents than those in Level 1, they would typically have a two- to three-person multidisciplined team to analyze the evidence and identify contributing causes and probable root causes.

7.3.2 Beginning the Level 2 PEI Incident Investigation

Similar to the Level 1 investigation, the Level 2 investigation would start with the incident report filled out with the knowledge about the incident known at the time. Developing a form or guidelines for gathering and recording the incident information will be useful when reviewing these investigations for trends and further improvements. See Annex A for a simple example form. It is important to properly define the problem that the investigation team is going to investigate. The incident might have caused multiple issues, such as loss of containment that then revealed improper fire monitor coverage or improper drainage when mitigating. These are different problems and should be investigated separately; the PEI incident investigation should address why the loss of containment occurred.

The owner-user's investigation program should define how a PEI incident investigation team leader is assigned and how a team is formed for a Level 2 investigation. The team composition should consider the type, size, consequences, and nature of the incident.

It is important to collect the available and relevant evidence as soon as safely and reasonably possible to do so. As part of establishing a PEI incident investigation program, it is helpful to have one or more trained and designated team member with the responsibility for arriving at the scene ready to collect and/or preserve evidence while the evidence still exists. For example, if an incident involves loss of containment, evidence gathering can begin outside the area even before the area is secured and safe to enter. This person(s) can begin collecting eyewitness statements, if the eyewitnesses are not involved in the emergency response, and also downloading DCS data. For Level 2 investigations that did not involve loss of containment, the program might include consideration on how to collect evidence at the scene immediately. For example, the designated team member or investigation leader responsible for initial evidence gathering should not be involved in the repair work that may be required because of the incident. This will allow the person to concentrate on evidence/data gathering and not miss an opportunity to collect data, such as while a piece of equipment is shut down, before a patch is installed over a corroded area, or before corrosion or fouling products are lost or disposed of. More details about evidence gathering are contained in 7.3.4.

7.3.3 PEI Level 2 Investigation Personnel

Defining the team composition requirements associated with a Level 2 investigation may be part of the PEI incident investigation program. The following are guidelines on the type and role of personnel that would be involved in Level 2 investigations.

a) *PEI Incident Investigation Team Leader*—The investigation leader should be trained in the specific investigation methodology used. For Level 2 investigations, the investigation team leader is responsible for leading the investigation team through the entire investigation process. The investigation team leader responsibilities include the following:

   1) conducting the investigation by the specific company methodology,

   2) defining the required resources or team members to help conduct the investigation,

   3) leading the team in collecting the evidence and analyzing the evidence in an unbiased way to determine the causes based on the evidence and facts,

   4) presenting to appropriate management the conclusions and recommendations,

   5) writing the final report.

b) *Team Members*—The size and complexity of the incident will determine the number of team members that are needed. The team may be comprised of a diverse mix of backgrounds from either the area where the incident occurred or another area within the facility in order to facilitate the thinking process from different perspectives. Either one team member or the team leader could be a PEI person; this could be an inspector, pressure equipment engineer, inspection engineer, metallurgical/corrosion engineer, or reliability engineer. The PEI team members should consist of knowledgeable but impartial people who were not directly involved in the incident. If the team leader sees indications that a person believes they have made a mistake and will be held culpable for the incident, then that person should not be selected as a team member.

   The investigation team members assist in the investigation by collecting evidence and helping to analyze the evidence to determine the causes. Team members may also be needed to assist the team leader in writing the final report.

c) *Sponsor*—The sponsor would typically be the process unit's area manager or could be the engineering manager or project manager, depending upon the type of incident.

The sponsor's role is to ensure that the team has the time, resources, and cooperation to conduct the investigation but is not to manage the activities of the investigation. The sponsor should convey to all those who will be assisting the investigation team the importance of their cooperative participation in the investigation. Additionally, the sponsor would be responsible for assuring that identified and approved corrective actions were implemented on a timely basis and that the lessons learned were communicated to affected individuals.

7.3.4 Collecting Evidence

7.3.4.1 General

The determination of immediate, contributing and root causes is based on evidence and expert knowledge of the contribution of the evidence. If not properly preserved or collected soon after the incident, some evidence can be lost, such as DCS data being overwritten, damaged components being thrown away, or fracture surfaces improperly handled. The priority for collecting data should be based on how perishable the data is. The more perishable or changeable data should be collected first. The team should begin collecting data without trying to solve why the incident occurred or determining the immediate, contributing, or root causes.

In PEI incidents that involve fires or toxic releases, once the area has been secured and it is safe for personnel to enter, evidence gathering should begin. The investigation lead will need to work with operations to control the scene until they determine that initial evidence gathering is complete. The area might be designated for no unauthorized entry. Collection of physical evidence would begin as soon as practical after securing the site and continues throughout the early part of the investigation. Collecting of other evidence not within the restricted area, such as interviewing of eyewitnesses, can begin immediately. The investigation team might begin a preliminary sequence of events timeline and sketch of the equipment or system involved to help the team understand what happened, what was involved, and the scope of the investigation.

The investigation team could survey the scene and identify people, equipment, and materials involved in the incident. The investigation leader could then prioritize the information to be gathered and assign responsibilities to the team members to conduct interviews and gather evidence. The coordination of the effort is to assure data is gathered systematically and purposefully.

One way to start determining what evidence to gather is to have a collection of generic lists for each type of evidence. These generic lists may be used by the team as a starting point and can be customized for the specific incident. An example of generic lists for each type of evidence is provided in Annex D. Depending on the type of incident being investigated, not all the evidence mentioned will be applicable or necessary to collect. If the incident did not have a defined consequence, like a loss of containment that happened suddenly, there may not be any eyewitnesses or process data at the time the incident occurred.

PEI personnel that are not on the investigation team can assist the investigation team by providing any information that they have about the equipment or system that was involved in the incident. They should be candid with any information they have, including historical information from memory, correspondence like email, and any notes in personal log books. Information should be freely provided to the team by the PEI personnel without any filtering or bias. In some cases, individuals may believe that they have made some sort of mistake or in some other way had a vital role in why the incident occurred. The investigation team should convey that they are not looking to blame any individuals but rather are just seeking the facts so that appropriate corrective actions can be applied to those management systems that are not as robust as they should be.

PEI and maintenance/repair personnel should not do anything with the equipment or system involved in the incident until the site has been released by the investigation team or team leader.

Consideration should be given to protecting the integrity of the evidence. Evidence, such as physical evidence, that cannot be replaced should be kept in a secure location such as a locked room or storage area and under the control of the investigation leader.

7.3.4.2 Collecting Evidence from People

The people evidence is one form of very perishable evidence. Immediately after an incident, people's recollection of the events begin to change, especially as they talk to others. It is important to initially interview the eyewitnesses and people directly involved in the incident as soon as possible. Ideally, they are asked not to talk to each other until they have been interviewed.

Interviewing people constitutes a major element in the initial stages of a PEI incident investigation. Some general guidelines for the interview process are as follows.

— Write questions to ask ahead of time to make the interview and note-taking go smoothly. It is good to have a template for interviewing that investigators use. An example of generic questions to ask eyewitnesses is included in Annex E, but it should be modified to suit the site-specific incident.

— Begin by interviewing the people directly involved in the incident and eyewitnesses first. People's recollection regarding details of what happened can change quickly, so timely interviews could be important.

— Interview individually to help keep the interview private and prevent individuals from influencing each other's memories. This also minimizes the intimidation factor associated with interviews.

— Interview at the scene, if practical/safe, to help the person being interviewed remember details.

— Explain that the intent of the investigation is to identify causes, not to place blame. Tell the interviewee that although their information may be used in the investigation, no names will be attached to specific statements.

— Avoid speculating, trying to solve the reason why, or identifying causes. You are just gathering information without judgment and should be careful not to influence their statements in any way. Start the interview with open-ended questions that cannot be answered with a one-word answer. For example, ask storytelling questions such as "Tell me what you saw?" and "What happened next?". Later in the interview, use closed-end questions to get more specific detail.

— Do not "lead" the interviewee; start the interview with broad questions (e.g. "Would you please tell me what you saw, heard, smelled?"). Leading questions indicate the answer as part of the question and may be useful in confirming what was said, but not in gathering overall information. For example, "You had recently inspected the piping and found xyz thickness?" is a leading question but may be useful in clarifying information after the interviewee tells you information. Leading questions are good for confirming understanding but not for pulling out the facts initially.

— Ask questions for clarification as necessary (e.g. "What do you mean when you say…?").

— Progress to more detailed questions (e.g. "Can you explain the procedure for...?").

— At the end, paraphrase what you heard to improve and confirm your understanding and provide the individual a chance to add more detail or make clarifications.

Information collected from interviewing people needs to be compared with information from other sources before stating as fact. Collaboration might include supporting interview statements with physical or records evidence or by multiple people independently making the same statements.

7.3.4.3 Collecting Physical Evidence

An initial site visit would occur as soon as the area where the incident occurred is determined to be safe for entry by investigation personnel. The investigation team or at least the investigation team leader would survey the site to look for physical evidence. They would look at the entire surrounding area and not just the point of the incident. They

would look for signs of evidence and also look for what should be there but is not. They would also look for what is correct and document that; this will be helpful later in confirming or disproving theories. The investigation team should not disturb anything at this point and should not be focused on fixing the problem or determining the cause. They should only be looking at recording, collecting, and documenting physical evidence.

The initial activities of the site survey might include the following and would typically be performed in the stated order.

— Take photographs of the scene from various angles and distances to help orient people to the incident. Consider the need and value of videotaping to add additional orientation and perspective to the scene. Take photographs of the surrounding areas and equipment. Placing a recognizable object or ruler next to the object being photographed may add perspective, particularly for close in photos of small objects. Using index cards to write what the object is and place in the photo helps with documenting the photographs.

— Write observations or make sketches for things that may not show up on a photograph (e.g. warped, discolored, cracked).

— Incidents that involved an explosion may require special mapping of the location of fragments and debris. It is important to map the exact location of any fragments and their condition. The size of the parts and the distance they are from the source are good information to determine the energy released.

— Collect any failed parts that do not require disassembly. Be very careful in handling damaged parts to preserve evidence that may be present on a macro or microscopic level. Label where the part came from and its orientation. Any equipment that requires disassembly should be done later under the direct observation of an investigation team member or FA laboratory.

— Samples of process fluids or solids that may be involved should be collected.

— Incidents that involved fires should have the damage of the material in the area recorded for determining the heat pattern. API 579 as well as NFPA 921 [4] provide guidelines for assessing fire damage.

— It is important to record what equipment was not damaged in the area or system involved.

Equipment damaged in an incident should be carefully preserved. Fracture surfaces should not be disturbed to prevent incidental damage and hinder the failure evaluation of the part. Similarly, cleaning of the part should not be done unless absolutely necessary to enable chemical analysis of the part.

When handling failed parts and fracture surfaces, care must be taken to preserve specimens in the original condition to provide as much information as possible for determination of the cause of the failure. For any failure, the following guidelines for preparation of samples for analysis should be followed, as appropriate.

— Do not mechanically clean, sandblast, wire brush, or acid clean any failed parts prior to proper analysis. Deposits on the failed part might be helpful in determining the cause(s) of the failure.

— If a part is fractured into two or more separate pieces, do not try to fit the fracture surfaces back together. Certain metallurgical features on the fracture face can help determine the cause of the failure and can be easily damaged by improper handling.

— Only apply preservatives (e.g. lubricating oil) to fracture surfaces when directed to do so. The lubricating oil can be removed prior to fractographic analysis; however, the integrity of surface deposits and corrosion products could be compromised by applying oil to fracture surfaces.

— Wrap the failed section in plastic (e.g. bubble wrap) in the "as-is condition" without removal of surface deposits beforehand.

— Do not store failed items outside.

If possible, a good practice is for the team to conduct an initial site survey and collect initial evidence, then take a break and come back later in the day or even the next day to survey the site again before cleanup or demolition begins. This provides the team the opportunity to see things that might have been missed on the first survey.

Generally, after this second site survey, the site is released from evidence gathering so that cleanup and repair activities can begin. During repair and restoration activities if any PEI personnel discover anything they think is unusual or they think might be relevant to the investigation, they should notify the investigation team leader immediately.

7.3.4.4 Collecting Record Evidence

It is important for the investigation team to concentrate on collecting the most perishable evidence as soon as practical. After that is complete, the investigation team would then brainstorm on what other evidence to collect. They could make a list of that evidence and the investigation team leader might assign responsibilities to the team members to gather the additional evidence. This additional evidence might include the following, depending on the type of PEI incident:

— Operating information showing process control data several days before the incident and at the time of the incident. (Process control information should be collected or archived as soon as possible. This should be an initial step backed up by further collection of information once the investigation is underway.)

— Related operating and maintenance procedures, including date last updated/reviewed.

— Copies of the appropriate design standards (engineering practices, design practices, etc.).

— Copies of management system documents related to the activities surrounding the incident, such as management of change documents.

— Copies of engineering drawings, piping and instrument diagrams (P&IDs), and job safety analyses.

— Operator log books and shift turnover documentation.

— Relevant maintenance and inspection records.

— Equipment design and construction records.

— Materials information.

— Applicable personnel training records.

7.3.5 Analyzing Evidence and Determining Causes for PEI Incidents

The collection of evidence and the analysis of evidence should be two distinct and separate activities. While collecting evidence, the team should not try to analyze it and determine causes too early. This can lead to bias and not exploring possible causes.

Once the investigation team leader believes that the team has collected all (or most of) the evidence, the team should begin analyzing the evidence. The investigation team should carefully review the evidence and make sure they fully understand what it is revealing. If this is a large investigation and there is a lot of evidence, it can be beneficial to divide up the different types of evidence among the team. Have one or two members of the team review each type of evidence—records, people, and physical—and summarize it. They would then present the summarized evidence to the rest of the team. Team members should draw conclusions from their reviewed evidence about the immediate, contributing, and root causes of the incident. Members would then present their conclusions to the team. The team

could then determine if each form of evidence is pointing to basically the same conclusions about causes. That would be further confirmation that the correct causes are being identified.

Once the team begins analyzing the evidence, some gaps in evidence may be revealed that will require collecting of more evidence. The team should then gather that additional evidence. Also, when the analysis of evidence begins this will reveal any expertise that is needed to help analyze data and determine causes, such as metallurgical expertise to examine failed components or process expertise to analyze process samples or process data.

Analyzing the evidence to determine the causes usually defines the issues associated with the incident such as:

1) type of failure or damage mechanism;

2) details of the components involved: material, service conditions, environment, stresses, and loadings;

3) prior service history;

4) manufacturing history;

5) design conditions.

Tests needed to analyze failed components and determine the causes would be specified by the proper expertise. Annex F is an example of a form that can be used to send physical parts off for FA and 7.5 gives guidance on FA of components.

One important part of the analysis would include determination of whether industry PEI codes and standards, such as those listed in 1.4, and company PEI-related procedures, standards, and work practices were followed or not. If they were followed, the analysis might determine why they were not effective in preventing the incident.

Use a structured analysis method to analyze the evidence and explain the failure, such as, logic tree, cause and effect diagrams, or sequence diagrams. There are many structured processes that can be found in the literature or offered by commercial vendors.

7.3.6 Developing Recommendations and Action Items

Once the investigation team has conducted a structured analysis and determined the immediate, contributing, and root causes of the PEI incident, it is important to develop recommendations and action items to address the cause(s). Once action items are satisfactorily completed and a management system created or reinforced to sustain the corrective actions, the likelihood of reoccurrence of the incident and other similar incidents should be reduced.

Recommendations resulting from the incident investigation should be developed to prevent reoccurrence of the condition or activity. The investigation team should not attempt to analyze the cost or engineering required to implement a recommendation, unless directed to do so by their sponsor. Generally, such efforts are part of the next phase to develop action items and typically involve different individuals.

For PEI incidents, consideration might be given to what changes are required to improve the PEI program in order to prevent similar incidents.

EXAMPLE The inspection plan for the equipment involved and other similar equipment should be reviewed to determine if it should be changed or modified in any way to prevent another such incident. Consideration should also be given to determination of whether any procedures, documented work practices, and other management systems need to be reviewed for improvement.

Each recommendation that the investigation team develops should be clearly written, should state which cause(s) it is designed to address, and should be clear and concise requiring no interpretation. A suitable implementation plan would then be developed to resolve the recommendations.

The investigation team will develop recommendations to address the causes identified as a result of the investigation. The investigation team may suggest action items to address their recommendations, but they do not typically define the action items and responsibility. This is more appropriately done by the management of the group or area that owns the issue or the group that has to commit resources or funding to solve the issue. It is management's responsibility to define appropriate action items to address the recommendations and assign the appropriate owner of the action item.

Action items assigned to address the investigation team's recommendations would typically be clearly written and state which recommendation it addresses. Alternative actions may be substituted by the responsible manager, or action items may be modified as corrective action work progresses, so long as the recommendation is adequately addressed and the proper approval is received. Action items are typically assigned a responsible owner with a reasonable completion date assigned; considering the risk associated with continued operation may influence the specified completion dates.

7.3.7 Final Report and Documentation

A final report is written by the investigation team that documents the PEI incident investigation effort, the findings, analyses, causes, and recommendations. The report may contain or reference the technical information used as part of the analysis.

Reports might include the following information:

— describe the incident—where and what happened;

— presentation of the findings of how and why the incident happened;

— presentation of the conclusions on what were the immediate, contributing, and root causes;

— indicate what management systems that may be related to the root causes;

— include the recommendations to prevent a repeat incident and/or lower the risk.

A standard template or consistent format for final reports assists those writing and reviewing reports and will help with documenting required information An example template for a Level 2 final report is included in Annex G.

The final report is only a portion of the overall record of the investigation. The final report and other documentation deemed necessary for recordkeeping per the company's record retention policy should be stored.

7.3.8 Tracking of Action Items

There should be a system in place to track progress and ultimate completion of action items assigned. The problems and issues discovered during a PEI incident investigation remain unchanged until the action items assigned to address them have been completed and a system is put in place to sustain the changes.

The owner/user should have a process whereby action items are periodically reviewed and progress monitored. Action items should be completed by the assigned target date. Action item target dates should not be changed without consideration of the risk associated and management review and approval. In some cases, there may also be regulatory requirements on the time allowed to implement certain actions. If an action item is changed or deleted, it should be documented as to why and how this decision was made and what alternative actions were taken. Action items should have an auditable trail.

The appropriate level of manager should be assigned to monitor the progress of action items.

7.3.9 Determining Effectiveness of Action Items

For a select number of PEI investigations, it may be important to review the effectiveness of the actions taken to resolve recommendations.

7.4 Level 3 PEI Incident Investigations

Most of the information in 7.3 for conducting a Level 2 investigation of a PEI incident also applies to Level 3 investigations of PEI incidents. It is assumed that most Level 3 PEI incident investigations would rise to the level of a process safety investigation. As such, the description herein of a Level 3 PEI incident investigation would need to be in conjunction with and in support of the site's process safety investigation procedure.

A Level 3 PEI incident investigation would likely be led and/or overseen by other parts of the organization (such as site managers, the site safety or process safety group) but would be supported by PEI personnel when loss of containment was an issue. Additional breadth and depth of investigation and root cause understanding is warranted for the PEI aspects of incidents with Level 3 actual or potential consequences. The following guidelines supplement those provided above for Level 2 PEI incident investigations.

Level 3 investigations are performed on the PEI incidents with the highest actual or potential consequence and require a multidisciplined team to fully analyze the deepest level of cause (root causes), as well as contributing causes and probable causes. Typically, only a very small percentage of PEI incidents would be investigated at this level of detail. This level of investigation is generally selected for incidents that had actual or potential to result in significant safety, health, or environmental consequences.

Typically, there is more than one cause in a Level 3 PEI incidents. Some of the causes may be latent (or hidden), or a cause cannot be verified to a high degree of certainty (referred to as a probable cause). In the refining and chemical processing industry, hazardous processes are protected by multiple layers of protection or barriers. Typically, more than one barrier or protection layer has to fail to have a catastrophic incident. For an incident that warrants a Level 3 investigation, the majority of the layers of protection would have failed or been weakened in some way. Some of the barriers might have latent or hidden weaknesses in them, but these had not been revealed or known before because the other barriers were preventing any incidents. It is important when conducting a Level 3 PEI incident investigation to determine the contributing weaknesses of the multiple layers of protection.

A structured RCA method should be used to analyze the evidence and explain the failure and the incident, including those methods such as logic trees, cause and effect diagrams, sequence diagrams, etc. Whichever method is used, the investigation results should be based on the evidence and facts and every effort made to eliminate bias. Development of these types of trees or diagrams will also reveal any additional evidence or data analysis to assure that the conclusions are thoroughly supported by the evidence.

The PEI incident investigation team leader/member should be a trained and experienced person in the specific RCA investigation methodology used. For Level 3 incidents, the PEI incident investigation leader might be someone from another area of the company or plant than where the incident occurred or even a contract principal investigator. It may also be beneficial for the team leader to have their primary area of technical expertise outside of the PEI functional discipline. This will reduce the potential for bias and overlooking some potential causes. The team leader should make sure that all evidence is gathered and considered to avoid predetermining causes and consequently the bias of gathering evidence to confirm these predetermined causes.

The team members might be a cross-functional group of individuals with knowledge and technical expertise in different functional disciplines. Team members who were not involved with or associated with the equipment being investigated are preferred to minimize introducing bias or conflicts of interest. PEI personnel from another area of the facility could serve as team members for pressure equipment failures to lend their knowledge and expertise to the investigation. If contractors are involved in the incident, then consideration should be given to including someone from the contractor's company on the team but not to someone that was directly involved in the incident.

Once a Level 3 incident is determined to be caused by a PEI failure then PEI personnel can lend their knowledge and expertise to the investigation team to improve evidence gathering and determination of causes. The following areas of expertise that PEI personnel may assist the investigation with include:

— knowledge of the PEI codes and standards (see 1.4) that apply and if any had not been followed or adhered too or were not effective;

— knowledge of the company PEI procedures and work practices;

— guidance in determining the specific damage mechanism that caused the failure and the type of FA that should be done on specific physical evidence;

— guidance in specifying NDEs to identify other damage in the remaining equipment. Help in reviewing past inspection records to determine if the damage should have been predicted and reasons it was not.

Level 3 investigations should be sponsored by site management who is responsible for safety, health, and environment. The sponsor's role is to ensure that the team has the time, resources, and cooperation to conduct the investigation.

The Level 3 investigation should identify the immediate, contributing, and root causes, with the investigation depth and scope supported by the investigation sponsor and fully utilizing the RCA methodology selected. The investigation should be extensive enough to fully understand the immediate causes (the specific equipment damage mechanisms that resulted in the failure) and also identify the contributing and root cause factors and systemic reasons (management systems and work culture) that caused or allowed the physical causes to exist and to progress to failure. Management system, work process, safety systems, and/or work culture root cause factors will be identified as defined by the specific RCA investigation methodology selected at the facility or company.

7.5 Component Failure Analysis

Laboratory FA of the component that led to the loss of containment is vital to many PEI incident investigations. Formal laboratory analysis should be completed for most failed components to determine failure mechanism. FA will typically involve some form of metallurgical FA of the failed component but could also be a FA on nonmetallurgical components and entail chemical analysis of deposits that might be helpful in identifying corrosion deposits, corrosive fluids, or fouling materials. As mentioned previously, it will be vital to protect the integrity of those components and samples to be analyzed.

Depending upon the level of investigation, an agreed upon protocol for selecting, shipping, examining, testing, and recording the failed specimens will be needed and should be agreed upon in the investigation team and with any other parties that may be involved (e.g. regulatory bodies). The protocol should cover at least five stages of handling the physical evidence that will be analyzed, namely:

1) selection of the samples;

2) packaging, handling, and shipping the samples;

3) documenting the various stages of analysis and handling;

4) examination and testing; and

5) reporting.

Annex F shows an example of a simple form for requesting a FA from an in-house company or contract FA firm.

Sometimes it will be obvious from the outset which component failed and caused the loss of containment. Other times because of the ensuing destruction and multiple equipment and piping failures due to the fire and explosion, it will not be so obvious which component failed first and which components may have failed because of the incident and consequence of the release (knock-on effects). In the latter case, multiple samples may need to be shipped from the site to the laboratory for analysis, not only to determine the physical cause of the loss of containment but also to determine which pieces of equipment may have failed as a result of the consequences that followed the original failure.

Preparing, handling, and shipping the samples needs to be sufficiently detailed with appropriate quality assurance/ quality control (QA/QC) to ensure that they arrive at the laboratory in the same condition that they were found at the site. Care to avoid potential handling and shipping damage will help to avoid erroneous or lack of conclusions during the FA due to damage that was not actually incurred during the incident. Shipping and handling protocol may need to specify type of packaging, type of crating, protection from the environment, need for desiccant, etc.

But even before investigators begin to define the protocol for FA work, they must decide where to send the samples for analysis. FA for PEI incident investigations should be performed by organizations competent, qualified, and experienced in refinery and chemical plant failure mechanisms. A best practice is to identify and evaluate firms and establish a business relationship prior to an incident.

The next major step in the FA part of a PEI incident investigation is to assemble, document, and agree upon the various required steps in the laboratory FA that is needed to support the PEI incident investigation analysis. The objective of this FA protocol is to perform metallurgical/material inspection, examination, and testing of the selected physical evidence items in an effort to identify failure modes and contributing damage mechanism that caused the PEI incident (i.e. determine the immediate physical cause for the loss of containment).

The investigation team should create a FA protocol with the input of the selected FA laboratory. Decisions will need to be made about the kinds and amount of testing and examination that will be required, including such things as:

— visual examination;

— sample preservation;

— physical measurements;

— NDE;

— cleaning methods and techniques;

— sample cutting, extraction, and marking;

— macro and micro metallographic examination;

— X-ray diffraction;

— scanning electron microscope examination;

— chemical analysis;

— energy dispersive X-ray spectroscopy examination;

— macro and/or micro hardness testing;

— fracture surface examination;

— deposit/residue collection and analysis; and

— mechanical testing.

The amount and type of documentation at every step should be agreed upon and included in the FA protocol, including such things as:

— When, where, and how much photographic and/or video documentation is needed;

— how much and what laboratory documentation is needed;

— the amount and type of sample marking/tagging;

— the need for hold points and witnessing of selected steps by members of the investigation team;

— at what point and when verbal reports of FA progress are needed; and

— details of what needs to be contained in the final report.

8 Training and Qualifications

8.1 General

When an incident occurs it is important to have the right people who are already trained to immediately respond and begin the investigation. Facility management should plan for team composition requirements and have trained and qualified people ready and available. Frontline supervisors of the organization need to know who to call and when, before an incident occurs. Everyone in the organization needs to know how to recognize incidents and how to report them.

8.2 Incident Investigation Team Leaders

The organization could define a pool of potential investigation team leaders. Example of training for team leads includes the following:

— an overview of the company incident investigation management system;

— investigation concepts;

— specific investigation techniques used by the organization;

— proper interviewing techniques;

— proper gathering of evidence;

— concepts of laboratory FA;

— how to analyze evidence for immediate and contributing causes using the methodology selected by the company;

— how to determine root causes;

— how to write effective recommendations;

— how to avoid bias in investigation analysis;

— documentation and report requirements.

PEI personnel should be trained on how to do an effective Level 1 investigation, while only select PEI and other personnel might be trained on how to lead a Level 2 investigation. Once trained, it is important that these potential team leaders practice the skills learned in the training to develop and maintain proficiency. The organization could also have a plan for periodic refresher training.

8.3 Incident Investigation Team Members

The organization may want to define a larger pool of potential investigation team members. Example of training material for team members include the following:

— an overview of the company incident investigation management system,

— investigation concepts,

— the specific investigation techniques used by the organization,

— proper interviewing techniques,

— proper gathering of evidence,

— documentation and report requirements.

8.4 Site Management Personnel

Site management should be knowledgeable in the following so they can support the process:

— incident investigation program and how it relates to the site/company PSM incident investigation management system,

— basic investigation concepts.

9 Continuous Improvement for PEI Incident Investigations

9.1 Information Sharing

Investigation reports may be made available to site personnel. Owners/users may consider sharing details of the incident within the industry to communicate learnings.

A communication bulletin summarizing key learnings may be beneficial for review within the facility at the conclusion of PEI incident investigations. It would typically contain a brief explanation of the incident and then explain the causes with particular emphasis on what others could do differently to reduce the risk of other adverse incidents. An example might be that one contributing cause of a PEI incident was adhering to IOWs for corrosion was not viewed as important as maintaining product quality process parameters, since most IOW were long-term developing issues. This is a mindset or cultural change that needs to be communicated and acted on throughout the organization.

Some example formats of PEI incident communication are:

— one-page bulletins distributed to supervisors for review with work groups,

— lessons learned documented and stored on an intracompany website,

— safety-type bulletins posted around the areas and distributed electronically.

9.2 Monitoring of the PEI Incident Investigation Program

The effectiveness of the PEI incident investigation program should be periodically reviewed to identify areas for improvement

Annex A
(informative)

Example Reporting Form for PEI Incidents [1]

General Incident Information		
Completed by:	Company/Site:	
Incident Date:	Incident Time:	
Area/Unit:	Equipment Involved:	
Incident Description: *Describe what happened and what you know about the incident.*		
Consequence: *Describe actual or potential.*		
Type of Incident/Equipment Involved		
Incident Classification:	Equipment Type:	Observations:
❒ Level 1—Low-consequence Incident	❒ Pressure Vessel	❒ Corrosion
❒ Level 2—Medium-consequence Incident	❒ Piping	❒ Cracking
❒ Level 3—High-consequence Incident	❒ Storage Tank	❒ Dripping
❒ Record incident data for compiling and analysis later, no investigation	❒ Rotating Equipment	❒ Hazardous Release
	❒ Boilers, Heaters	❒ Frire
	❒ Heat Exchangers	❒ Smoking
	❒ Pressure-relief Device	❒ Spray
	❒ Structural System	❒ Staining
	❒ Flange Joint	❒ Incorrect Spec
	❒ Other (describe)	❒ QA/QC Problem

[1] The following examples are merely examples for illustration purposes only. [Each company should develop its own approach.] They are not to be considered exclusive or exhaustive in nature. API makes no warranties, express or implied for reliance on or any omissions from the information contained in this document.

Annex B
(informative)

Example Application of the "5-Whys" Investigation Methodology [2]

B.1 Description

The "5-Whys" tool is a simple process to follow to determine the causes of incidents. This method adds some structure to brainstorming on causes and does utilize a logic tree approach without actually drawing the logic tree diagram. This method is dependent on the judgment and experience of the person or group that is asking why. The method is typically best used for simple problems without multiple causal factors.

It is important to begin the process with a clear problem statement that defines the incident that is being investigated. Once the problem statement is determined, you begin asking why to the problem statement and then ask why again to that, typically after asking why five times you have reached the contributing and root cause. If you have not, then you continue to ask why until you reach the root cause. In some cases the root cause is reached in less than five whys, so five whys is just a guideline and a name for the process.

B.2 Example

This example demonstrates the basic method of the 5-Whys.

During a plant's maintenance turnaround, an exchanger bundle was pulled, cleaned, and inspected. The tubes were discovered to have corrosion damage and numerous leaks, and the number of tubes needing plugging would exceed 20 % of the tubes and therefore would be too many. It was determined the best course of action was to have a new bundle built and sent to the plant. The unit mechanical engineer pulled the heat exchanger drawings from the main records center and sent those to the fabricator. The new bundle was built and shipped to the plant only a few days before the turnaround was scheduled to end. When the maintenance crews went to install the new bundle in the existing shell, it was discovered it would not fit. The heat exchanger had been modified sometime in the past. At this point the plant had to plug the old exchanger bundle leaking tubes and put it back in service. The unit rates were reduced to accommodate the large number of plugged tubes. Block valves were also installed around this exchanger so that it could be taken out of service online and the correct tube bundle built and installed later.

The unit mechanical engineer decided to conduct a Level 1 investigation on this incident, since it did cost additional maintenance dollars to have another bundle built, install the isolation block valves, and then install the new second bundle. There were also associated production losses due to having to run at reduced rates for two weeks.

Because this unit mechanical engineer had only been assigned to this unit for about two years, he did not have knowledge of the change made to this exchanger. As part of his investigation, he talked with unit operators who had been on the unit for a long time. The operators remembered some issues with that exchanger about 10 years ago. He also talked with the unit process engineer about why the change was made. The unit mechanical engineer then reviewed the inspection records for this exchanger, and he could see that the ultrasonic thickness data showed that that the exchanger was renewed about 10 years before, but there was no explanation of why. There was also a file cabinet in his office of files that he inherited from the previous unit engineers. He looked through that file cabinet and found the correct drawings for the existing exchanger bundle.

[2] The following examples are merely examples for illustration purposes only. [Each company should develop its own approach.] They are not to be considered exclusive or exhaustive in nature. API makes no warranties, express or implied for reliance on or any omissions from the information contained in this document.

After looking at the data collected and also using his knowledge of the records system at the plant, he began his 5-Why analysis. The following is the 5-Why form he filled out.

NOTE A separate Level 1 investigation might need to be conducted on why the tube bundle had so many tubes needing plugging and why the bundle corrosion was so severe that it was not anticipated or planned for.

5-Whys Worksheet	
Name of Investigator: John Smith	**Date:** January, 15, 2010
Equipment Involved: E-101	**Persons Involved:**
What Happened That Should Not Have: E-101 replacement exchanger bundle was fabricated incorrectly.	
1. Why? The wrong drawings were used to fabricate the replacement bundle.	
2. Why? The drawings of the exchanger bundle were not updated in the main equipment files.	
3. Why? A previous unit engineer did not update the equipment file when the exchanger was redesigned.	
4. Why? The previous unit engineer did not trust the records room equipment files and so he kept his own files.	
5. Why? The records room does not have controlled access and documents have been lost or misplaced in the past.	
6. Why? Keeping up to date equipment files is not given a high priority by management.	
You have gotten to the end of asking why when you have identified the system related issues that can be corrected to prevent this incident from happening again.	
Identified Root Cause: The equipment files record room is not secured and there is not a defined and auditable process for updating records.	
Corrective Actions to Prevent Reoccurrence: Actions would be identified on how to improve the security of the equipment records room and to develop an auditable process for updating equipment records, with identified roles and responsibilities. This would be assigned to the plant technical manager.	

Annex C
(informative)

Example: Level 1 PEI Incident Investigation Results Form [3]

Incident: *What should be investigated?*	Date of Incident:
Investigation Method:	
Analysis Method:	Investigation Leader:
Team Members: *Name, job, and area, if any*	
Sponsor: *Name and title*	Date Investigation Initiated:
Date Investigation Completed:	Report Completed:
Investigation Results	
Evidence: *Summarize the evidence gathered.*	
Sequence of Events or Timeline: *Provide a brief timeline leading up to and including the incident.*	
Immediate Causes: *Explain the PHYSICS of the incident, define the causes that directly related to the incident.*	
Contributing Causes: *What were the causes that contributed to this incident or the severity of it?*	
Root Causes: What were the underlying system related reason the incident occurred.	
Follow-up Action Items:	

[3] The following examples are merely examples for illustration purposes only. [Each company should develop its own approach.] They are not to be considered exclusive or exhaustive in nature. API makes no warranties, express or implied for reliance on or any omissions from the information contained in this document.

Annex D
(informative)

Example Lists of Generic Evidence to be Gathered [4]

People data:

— eyewitness reports,

— first responders/emergency responders reports,

— process operators—on shift and off shift,

— maintenance personnel associated with the equipment,

— inspection personnel associated with the equipment,

— metallurgist or corrosion engineer,

— process engineers,

— reliability or maintenance engineers,

— project/design engineers,

— manufacturer's representatives,

— chemistry and other laboratory personnel.

Physical data:

— pressure boundary equipment such as gaskets and flanges;

— damaged equipment components;

— process samples from relevant equipment;

— metallurgical samples;

— explosion fragments and pieces of process equipment;

— direction of glass pieces;

— location and position of fragments;

— process volumes and levels;

— blast and fire damage;

— location of burn and scorch marks;

— as-found position of valves, controls, and switches;

[4] The following examples are merely examples for illustration purposes only. [Each company should develop its own approach.] They are not to be considered exclusive or exhaustive in nature. API makes no warranties, express or implied for reliance on or any omissions from the information contained in this document.

— position of relief valves;

— location of witnesses;

— location of other personnel involved in the process;

— smoke traces;

— melting patterns;

— impact marks;

— location of chemicals in the process;

— video recordings of the area, if available.

Record data:

— process operating records and conditions—electronic and manual,

— process operating procedures,

— shift logs,

— work permits,

— maintenance records,

— inspection records,

— records of process sample analyses,

— repair records,

— P&IDs,

— equipment drawings and specification sheets,

— repair and rerating records,

— material balances,

— corrosion data,

— management of change records,

— prior incident investigation reports or near miss reports,

— training manuals and records,

— inspection plans.

Annex E
(informative)

Examples of Questions to Ask Eyewitnesses [5]

— What do you do here, and what is your job?

— How long have you been doing that job?

— How long have you been at this facility/plant?

— Where were you at the time of the incident?

— What were you doing at the time of the incident?

— Would you describe the incident?

— What did you see, hear, feel, or smell?

— What did you do in reaction to the incident?

— How did you know what to do when the incident occurred?

— Who else was around you at the time of the incident?

— What were the others doing right before the incident?

— What were you doing right before the incident happened?

— Did you have any indications before the incident that something was about the happen?

— What were the weather conditions when the incident occurred?

— Was there anything different right before the incident?

— In your opinion why do you think this incident occurred? (Note this information as opinion, not fact.)

— Was this incident unexpected, or were you expecting something like this might happen and why?

— Has this incident or a very similar event occurred previously and if so, when and what happened?

[5] The following examples are merely examples for illustration purposes only. [Each company should develop its own approach.] They are not to be considered exclusive or exhaustive in nature. API makes no warranties, express or implied for reliance on or any omissions from the information contained in this document.

Annex F
(informative)

Request for Failure Analysis Form [6]

From:	**Date:**
To:	
ANALYSIS REQUIREMENTS	
Prioritization Category: A—Urgent Request—if work requires overtime or work after hours B—Standard Request—if work will be conducted during regular business hours	
Requested Due Dates: Verbal Report: Final Report:	
How Shipped: Carrier: Expected Date of Arrival: Tracking No.:	
Shipped To:	

BACKGROUND	
Type of Component: *shell, head, nozzle, pipe, flange, valve, etc.*	Material Type:
Equipment No.:	ASTM/ASME Spec No.:
Unit:	Wall Thickness:
Operating Dept:	Year Built:

PROCESS/DESIGN CONDITIONS	
Process Design Temperature: _____ °F	Process Operating Temperature: _____ °F
Process Design Pressure: _____ psig	Process Operating Pressure: _____ psig
Internal Environment (including major/minor fluids and contaminant):	
External Environment (including major/minor fluids and contaminant):	

[6] The following examples are merely examples for illustration purposes only. [Each company should develop its own approach.] They are not to be considered exclusive or exhaustive in nature. API makes no warranties, express or implied for reliance on or any omissions from the information contained in this document.

How Was the Problem Discovered?
Definition of Problem?
Type of Investigation Needed (please include drawings and datasheets as applicable):
Special Requests: *chemical analysis, special testing, PMI, mechanical testing, etc.*
Impact of Investigation on Business and Future Utilization of Equipment:
Contacts—Recipient of Verbal Failure Analysis Results/Conclusions by Phone:

Annex G
(informative)

Example Template for Level 2 or Level 3 PEI Incident Investigation Report [7]

The following sections are suggested as a template for an investigation final report.

Incident Description: *Provide a summary of the incident that occurred and that was investigated.*
Summary of Consequences: *Provide a summary of the consequences of the incident. This would include a summary of the injuries if there were any, environmental damage, a summary of the equipment damage, the production loss and down time, and associated costs.*
Investigation Process: *Describe in general how the incident was investigated. This would include the makeup of the team, when the investigation started after the incident, how long it took, and an overview of all that was done to investigate the incident.*
Summary Sequence of Events: *Brief summary of the major events leading up to and immediately after the incident in chronological order.*
Evidence: *An overview of what evidence was gathered and how it was.*
Evidence from People: *Provide a summary of the evidence that was gathered from people, including who was interviewed and job titles.*
Key Findings from Evidence Gathered from People: *A summary of the key findings from the evidence that was gathered from people.*
Physical Evidence: *A summary of the physical evidence that was examined and the key findings from it.*
Record Evidence: *A summary of the record evidence and the key findings from it.*
Incident Sequence: *Describe how the incident occurred and the events leading up to it.*
Immediate Causes: *Define the immediate physical causes that allowed the incident to occur based on the evidence gathered and the investigation team's analysis of that evidence.*
Contributing Causes: *Define the contributing causes of this incident based on the evidence gathered and investigation team's analysis of that evidence.*
Root Causes: *Define the root causes of this incident based on the evidence gathered and investigation team's analysis of that evidence.*
Recommendations: *Define the recommendations to mitigate the contributing and root causes in order to reduce the likelihood that they will contribute to another incident.*
Appendix: *The appendices would include more detail about the investigation team's findings. They might include further detail on key physical evidence, such as photos of failed parts and how the analysis was completed and what the analysis discovered. A more detailed timeline could be provided in the appendix, if one was developed. If a logic tree or sequence diagram is drawn for the investigation conclusions, those should be included in an appendix.*

[7] The following examples are merely examples for illustration purposes only. [Each company should develop its own approach.] They are not to be considered exclusive or exhaustive in nature. API makes no warranties, express or implied for reliance on or any omissions from the information contained in this document.

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[1] CCPS [8], *Guidelines for Investigating Chemical Process Incidents*, 2003

[2] CCPS, *Guidelines for Design Solutions for Process Equipment Failures*, 1998

[3] CCPS, *Guidelines for Risk Based Process Safety*, 2007

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[6] Kletz, Trevor, *What Went Wrong? Case Histories of Process Plant Disasters,* Fourth Edition, Gulf Publishing Company, 1999

[7] Latino, Robert J., and Latino, Kenneth C., *Root Cause Analysis: Improving Performance for Bottom-Line Results*, CRC Press LLC, 2002

[8] Nelms, C. Robert, *What You Can Learn from Things That Go Wrong*, C. Robert Nelms Publisher, 1996

[9] Lees, F. P., *Loss Prevention in the Process Industries*, Elsevier, 1996

[10] API 510, *Pressure Vessel Inspection Code*;

[11] API 570, *Piping Inspection Code*;

[12] API Recommended Practice 571, *Damage Mechanisms Affecting Fixed Equipment in the Refining Industry*;

[13] API Recommended Practice 572, *Inspection Practices for Pressure Vessels*;

[14] API Recommended Practice 573, *Inspection of Fired Boilers and Heaters*;

[15] API Recommended Practice 574, *Inspection Practices for Piping System Components*;

[16] API Recommended Practice 575, *Inspection of Atmospheric and Low Pressure Storage Tanks*;

[17] API Recommended Practice 576, *Inspection of Pressure-Relieving Devices*;

[18] API Recommended Practice 577, *Welding Inspection and Metallurgy*;

[19] API Recommended Practice 578, *Material Verification Program for New and Existing Alloy Piping Systems*;

[20] API Recommended Practice 579, *Fitness-For-Service*;

[21] API Recommended Practice 580, *Risk-Based Inspection*;

[22] API Recommended Practice 581, *Risk-Based Inspection Methodology*;

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[8] American Institute of Chemical Engineers, Center for Chemical Process Safety, 3 Park Avenue, 19th Floor, New York, New York 10016, www.aiche.org/ccps.

[9] National Fire Protection Association, 1 Batterymarch Park, Quincy, Massachusetts 02169-7471, www.nfpa.org.

[23] API Recommended Practice 582, *Welding Guidelines for the Chemical, Oil and Gas Industries*;

[24] API Recommended Practice 583, *Corrosion Under Insulation and Fireproofing* (pending publication);

[25] API Recommended Practice 584, *Integrity Operating Windows* (pending publication);

[26] API Standard 653, *Tank Inspection, Repair, Alteration and Reconstruction*;

[27] API Publication 932-A, *The Study of Corrosion in Hydroprocess Reactor Effluent Air Cooler Systems*;

[28] API Publication 932-B, *Design, Materials, Fabrication, Operation, and Inspection Guidelines for Corrosion Control in Hydroprocessing Reactor Effluent Air Cooler (REAC) Systems*;

[29] API Recommended Practice 939-C, *Guidelines for Avoiding Sulfidation (Sulfidic) Corrosion Failures in Oil Refineries*;

[30] API Recommended Practice 941, *Steels for Hydrogen Service at Elevated Temperatures and Pressures in Petroleum Refineries and Petrochemical Plants*;

[31] API Recommended Practice 945, *Avoiding Environmental Cracking in Amine Units*.

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Ex. I - 12

Response to Data Request

Blade Response to SoCalGas Data Request

Prepared for:
Messrs. A. Patel and G. Healy

Purpose:
Blade response to the SoCalGas Data Request January 23, 2020.

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Feb. 14, 2020

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1

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Version Record

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Version	Date	Description of Change

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1 Background

Southern California Gas Company (SoCalGas) issued a data request to Blade Energy Partners (Blade) on January 23, 2020.

Blade reviewed the data request and prepared responses to each part of the data requests. The SoCalGas questions are included verbatim followed by the Blade responses in Section 2.

2 Questions and Responses

2.1 Question 1.

With regards to YOUR statement in the BLADE REPORT, at p. 5-6, that "the root causes for the uncontrolled release of hydrocarbons for 111 days from SS-25 were … [t]he lack of internal policy and regulation that required production casing wall thickness inspections … methodologies such as periodic wall thickness measurements were necessary," please respond to the following questions:

2.2 Question 1.a.

Identify and describe any and all INDUSTRY STANDARD(S) that YOU considered, evaluated, or assessed in connection with internal policies requiring production casing wall thickness inspections.

2.2.1 Response 1.a.

Blade did not identify any INDUSTRY STANDARD(S) "in connection with internal policies requiring production casing wall thickness inspections".

2.3 Question 1.b.

Produce any and all DOCUMENTS related to any INDUSTRY STANDARDS identified in response to Request 1(a) above.

2.3.1 Response 1.b.

No INDUSTRY STANDARD(S) were identified with "in connection with internal policies requiring production casing wall thickness inspections".

2.4 Question 1.c.

For each of the INDUSTRY STANDARD(S) identified in response to Request 1(a) above, describe the reason(s) why BLADE evaluated the INDUSTRY STANDARD(S)

2.4.1 Response 1.c.

No INDUSTRY STANDARD(S) were identified with "in connection with internal policies requiring production casing wall thickness inspections".

2.5 Question 1.d.

Identify any and all LAW(S) that YOU considered, evaluated, or assessed in connection with the above statement.

2.5.1 Response 1.d.

Blade reviewed the October 2015 version of the *California Statutes and Regulations for Conservation of Oil, Gas, and Geothermal Resources* [1] as described in the Blade Report on pages 197 – 199—Section 4.6.1.

2.6 Question 1.e.

For each LAW(S) that YOU evaluated in preparing the BLADE REPORT identified in response to Request 1(d) above, state YOUR understanding as to whether SoCalGas complied with the LAW(S).

2.6.1 Response 1.e.

Based on Blade's technical review, no requirements were identified in the October 2015 version of the *California Statutes and Regulations for Conservation of Oil, Gas, and Geothermal Resources* [1] requiring operators to conduct wall thickness inspections in gas storage wells. This is discussed on page 202—Section 4.7 of the Blade Report.

2.7 Question 1.f.

For each LAW(S) identified in response to Request 1(d) above, describe the reason(s) why BLADE evaluated the LAW(S).

2.7.1 Response 1.f.

An outcome of the RCA process was that the leak could have been prevented if a SoCalGas internal policy and regulations had been in place requiring periodic inspections to determine casing wall thickness as discussed on page 231—Section 5.3.1 and pages 237 – 238—Section 5.3.2 in the Blade Report. Periodic inspections would have allowed tracking wall thickness vs. time and provided data for assessing the pressure capacity of the production casing.

Therefore, Blade evaluated the regulations to determine if regulations were in place prior to the SS-25 leak that required production casing wall thickness inspections. Blade's assessment of the 2015 regulations is included in the Blade Report on pages 197 – 199—Section 4.6.

2.8 Question 2.

With regards to YOUR statement in the BLADE REPORT, at p. 5-6, that "the root causes for the uncontrolled release of hydrocarbons for 111 days from SS-25 were … [t]he lack of a real-time, continuous pressure monitoring system for well surveillance," please respond to the following questions:

2.9 Question 2.a.

Identify and describe any and all INDUSTRY STANDARD(S) that YOU considered, evaluated, or assessed related to real-time, continuous pressure monitoring systems for well surveillance.

2.9.1 Response 2.a.

Blade did not identify any INDUSTRY STANDARD(S) "related to real-time, continuous pressure monitoring systems for well surveillance."

2.10 Question 2.b.

Produce any and all DOCUMENTS related to any INDUSTRY STANDARDS identified in response to Request 2(a) above.

2.10.1 Response 2.b.

No INDUSTRY STANDARD(S) were identified "related to real-time, continuous pressure monitoring systems for well surveillance."

2.11 Question 2.c.

For each of the INDUSTRY STANDARD(S) identified in response to Request 2(a) above, describe the reason(s) why BLADE evaluated the INDUSTRY STANDARD(S)

2.11.1 Response 2.c.

No INDUSTRY STANDARD(S) were identified "related to real-time, continuous pressure monitoring systems for well surveillance."

2.12 Question 2.d.

Identify any and all LAW(S) that YOU considered, evaluated, or assessed in connection with the above statement.

2.12.1 Response 2.d.

Blade reviewed the October 2015 version of the *California Statutes and Regulations for Conservation of Oil, Gas, and Geothermal Resources* [1] as described in the Blade Report on pages 197 – 199—Section 4.6.1.

2.13 Question 2.e.

For each LAW(S) that YOU evaluated in preparing the BLADE REPORT identified in response to Request 2(d) above, state YOUR understanding as to whether SoCalGas complied with the LAW(S).

2.13.1 Response 2.e.

Based on Blade's technical review, no requirements were identified in the October 2015 version of the *California Statutes and Regulations for Conservation of Oil, Gas, and Geothermal Resources* [1] requiring "a real-time, continuous pressure monitoring system for well surveillance."

2.14 Question 2.f.

For each LAW(S) identified in response to Request 2(d) above, describe the reason(s) why BLADE evaluated the LAW(S).

2.14.1 Response 2.f.

An outcome of the RCA process was that the lack of a real-time, continuous pressure monitoring system for well surveillance prevented an immediate identification of the SS-25 leak and accurate estimation of the gas flow rate. The SS-25 gas injection could have been stopped earlier preventing additional cooling at the leak and may have prevented the brittle failure that caused the production casing to circumferentially part resulting in the large breach in the casing. This is discussed in the Blade Report on page 230—Section 5.2.3, page 233—Section 5.3.1, and page 239—Section 5.4.

Therefore, Blade evaluated the regulations to determine if regulations were in place prior to the SS-25 leak that required "real-time, continuous pressure monitoring system for well surveillance."

2.15 Question 3.

With regards to YOUR statement in the BLADE REPORT, at p. 5-6, that "the root causes for the uncontrolled release of hydrocarbons for 111 days from SS-25 were … "[t]he lack of systemic practices of external corrosion protection for surface casing strings," please respond to the following questions:

2.16 Question 3.a.

Identify and describe any and all INDUSTRY STANDARD(S) that YOU considered, evaluated, or assessed in connection with external corrosion protection for surface casing strings.

2.16.1 Response 3.a.

Blade considered the NACE Standard Practice SP0186-2007 titled "Application of Cathodic Protection of External Surfaces of Well Casings" [2] (formerly RP0186-2001).

The foreword from SP0186-2007 describes the standard as follows:

> This NACE International standard practice identifies procedures to determine the need for cathodic protection (CP) and the current requirements to achieve CP of well casings associated with oil and gas production and gas storage. It also outlines practices for the design and installation of CP systems and for their operation and maintenance.

2.17 Question 3.b.

Produce any and all DOCUMENTS related to any INDUSTRY STANDARDS identified in response to Request 3(a) above.

2.17.1 Response 3.b.

NACE Standard SP0186-2007 can be purchased from the NACE website.

2.18 Question 3.c.

For any INDUSTRY STANDARD(S) identified in response to Request 3(a) above, describe the reason(s) why BLADE evaluated the INDUSTRY STANDARD(S).

2.18.1 Response 3.c.

An outcome of the RCA process was that the lack of systematic practices of external corrosion protection for surface casing strings was one of the root causes for the release of hydrocarbons. This is discussed several places in the Blade Report including, page 99—Section 2.7.4; page 124—Section 2.10.2, page 193—Section 4.5, page 205—Section 4.7, page 233—Section 5.3.1, and page 239—Section 5.4.

Therefore, Blade considered the NACE Standard Practice SP0186-2007 and RP0186-2001 to determine whether the SP/RP criteria, applied to SS-25 conditions, would have identified a need for cathodic protection of the surface casing.

2.19 Question 3.d.

For any INDUSTRY STANDARD(S) identified in response to Request 3(a) above, describe how long before the October 23, 2015 leak they were published or otherwise made available.

2.19.1 Response 3.d.

The NACE standard RP0186 was published in 2001, and SP0186, which superseded RP0186, was published in 2007.

2.20 Question 3.e.

Identify any and all LAW(S) that YOU considered, evaluated, or assessed in connection with the above statement.

2.20.1 Response 3.e.

Blade reviewed the October 2015 version of the *California Statutes and Regulations for Conservation of Oil, Gas, and Geothermal Resources* [1] as described in the Blade Report on pages 197 – 199—Section 4.6.1.

2.21 Question 3.f.

For each LAW(S) that YOU evaluated in preparing the BLADE REPORT identified in response to Request 3(e) above, state YOUR understanding as to whether SoCalGas complied with the LAW(S).

2.21.1 Response 3.f.

Based on Blade's technical review, no requirements were identified for cathodic protection of surface casings in the October 2015 version of the *California Statutes and Regulations for Conservation of Oil, Gas, and Geothermal Resources* [1].

2.22 Question 3.g.

For each LAW(S) identified in response to Request 3(e) above, describe the reason(s) why BLADE evaluated the LAW(S).

2.22.1 Response 3.g.

An outcome of the RCA process was that the lack of systematic practices of external corrosion protection for surface casing strings was one of the root causes for the release of hydrocarbons. This is discussed several places in the Blade Report including, page 99—Section 2.7.4, page 124—Section 2.10.2, page 193—Section 4.5, page 205—Section 4.7, page 233—Section 5.3.1, and page 239—Section 5.4.

Therefore, Blade considered the October 2015 version of the *California Statutes and Regulations for Conservation of Oil, Gas, and Geothermal Resources* [1] to determine any requirements "in connection with external corrosion protection for surface casing strings".

2.23 Question 4.

With regards to YOUR statement in the BLADE REPORT, at p. 5-6, that "the root causes for the uncontrolled release of hydrocarbons for 111 days from SS-25 were … "[t]here was no quantitative understanding of well deliverability, although data were available, and well-established industry practices existed for such analysis," please respond to the following questions:

2.24 Question 4.a.

Identify and describe any and all INDUSTRY STANDARD(S) that YOU considered, evaluated, or assessed in connection with the above statement.

2.24.1 Response 4.a.

Well deliverability analysis is a long-established and widely used practice by the petroleum industry.

Blade used the following handbooks and textbooks in conducting well deliverability analysis:

- *Production Optimization Using Nodal Analysis*, H. Dale Beggs, OGCI Publications, 1991
- *Petroleum Production Systems*, First Edition, M.J. Economides, A.D. Hill, C. Ehlig-Economides, Prentice Hall, 1994
- *Petroleum Production Systems*, Second Edition, M.J. Economides, A.D. Hill, C. Ehlig-Economides, D. Zhu, Prentice Hall, 2013

Blade used PROSPER, a commercially available software, which is widely used in the petroleum industry.

2.25 Question 4.b.

Produce any and all DOCUMENTS related to any INDUSTRY STANDARDS identified in response to Request 4(a) above.

2.25.1 Response 4.b.

These documents are available for purchase online.

2.26 Question 4.c.

For each of the INDUSTRY STANDARD(S) identified in response to Request 4(a) above, describe the reason(s) why BLADE evaluated the INDUSTRY STANDARD(S)

2.26.1 Response 4.c.

An outcome of the RCA process was that the lack of understanding of the well deliverability was a root cause and affected the well-control planning as discussed in the Blade Report on pages 132 – 133—Section 3.2.1. Well gas flow rate is a key parameter used in dynamic kill modeling and in estimating the total gas leak volume.

Therefore, Blade used industry practices to establish well deliverability following the leak event.

2.27 Question 4.d.

Identify any and all LAW(S) that YOU considered, evaluated, or assessed in connection with the above statement.

2.27.1 Response 4.d.

Blade reviewed the October 2015 version of the *California Statutes and Regulations for Conservation of Oil, Gas, and Geothermal Resources* [1] as described in the Blade Report on pages 197 – 199—Section 4.6.1.

2.28 Question 4.e.

For each LAW(S) that YOU evaluated in preparing the BLADE REPORT identified in response to Request 4(d) above, state YOUR understanding as to whether SoCalGas complied with the LAW(S).

2.28.1 Response 4.e.

Based on Blade's technical review, no requirements were identified for well deliverability estimation in the October 2015 version of the *California Statutes and Regulations for Conservation of Oil, Gas, and Geothermal Resources* [1].

2.29 Question 4.f.

For each LAW(S) identified in response to Request 4(d) above, describe the reason(s) why BLADE evaluated the LAW(S).

2.29.1 Response 4.f.

An outcome of the RCA process was that the lack of understanding of the well delivery was a root cause and affected the well-control planning as discussed in the Blade Report on pages 132 – 133—Section 3.2.1. Well gas flow rate is a key parameter used in dynamic kill modeling and in estimating the total gas leak volume.

Therefore, Blade reviewed the October 2015 version of the *California Statutes and Regulations for Conservation of Oil, Gas, and Geothermal Resources* [1] to identify any requirements for estimating well deliverability.

2.30 Question 5.

With regards to YOUR statement in the BLADE REPORT, at p. 217, that "no failure analysis or subsequent risk assessment was done that may have led to an awareness that corrosion was a potential problem," please respond to the following questions:

2.31 Question 5.a.

Identify and describe any and all INDUSTRY STANDARD(S) that YOU considered, evaluated, or assessed related to "failure analysis or subsequent risk assessment" related to gas storage well casings.

2.31.1 Response 5.a.

There are no specific standards or practices related to "failure analysis or subsequent risk assessment" related to gas storage well casings. However, Blade considered and evaluated API RP 585, *Pressure Equipment Integrity Incident Investigation* [3].

Blade considered API RP 1171 *Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs* [4] published in September 2015 that does address risk assessments for gas storage wells.

2.32 Question 5.b.

Produce any and all DOCUMENTS related to any INDUSTRY STANDARDS identified in response to Request 5(a) above.

2.32.1 Response 5.b.

API RP 585 and API RP 1171 can be obtained from the API website.

2.33 Question 5.c.

For each of the INDUSTRY STANDARD(S) identified in response to Request 5(a) above, describe the reason(s) why BLADE evaluated the INDUSTRY STANDARD(S)

2.33.1 Response 5.c.

An outcome of the RCA process was that a direct cause of the release of hydrocarbons was an axial rupture due to external microbial corrosion on the 7 in. casing outside diameter caused by ground water. A root cause was the lack of a detailed follow-up investigation failure analyses, or RCA of casing leaks, parted casings, or other failure events as discussed in the Blade Report on page 237—Section 5.3.2. The lack of failure analyses and risk assessments related to corrosion are discussed on page 232—Section 5.3.1.

Therefore, Blade reviewed industry standards to establish industry practices regarding failure analysis and subsequent risk assessments.

2.34 Question 5.d.

Identify any and all LAW(S) that YOU considered, evaluated, or assessed in connection with the above statement.

2.34.1 Response 5.d.

Blade reviewed the October 2015 version of the *California Statutes and Regulations for Conservation of Oil, Gas, and Geothermal Resources* [1] as described in the Blade Report on pages 197 – 199—Section 4.6.1.

2.35 Question 5.e.

For each LAW(S) that YOU evaluated in preparing the BLADE REPORT identified in response to Request 5(d) above, state YOUR understanding as to whether SoCalGas complied with the LAW(S).

2.35.1 Response 5.e.

Based on Blade's technical review, no requirements were identified for failure analysis or subsequent risk assessments in the October 2015 version of the *California Statutes and Regulations for Conservation of Oil, Gas, and Geothermal Resources* [1].

2.36 Question 5.f.

For each LAW(S) identified in response to Request 5(d) above, describe the reason(s) why BLADE evaluated the LAW(S).

2.36.1 Response 5.f.

An outcome of the RCA process was that a direct cause of the release of hydrocarbons was an axial rupture due to external microbial corrosion on the 7 in. casing outside diameter caused by ground water. A root cause was the lack of a detailed follow-up investigation failure analyses, or RCA of casing leaks, parted casings, or other failure events as discussed in the Blade Report on page 237—Section 5.3.2. The lack of failure analyses and risk assessments related to corrosion are discussed on page 232—Section 5.3.1.

Therefore, Blade reviewed the October 2015 version of the *California Statutes and Regulations for Conservation of Oil, Gas, and Geothermal Resources* [1] to identify requirements regarding failure analysis and subsequent risk assessments.

2.37 Question 6.

With regards to YOUR statement in the BLADE REPORT, at p. 237, that "[t]he root causes for the uncontrolled release of hydrocarbons for 111 days from SS-25 were . . . The lack of a dual mechanical barrier system in the wellbore," please respond to the following questions:

2.38 Question 6.a.

Identify and describe any and all INDUSTRY STANDARD(S) that YOU considered, evaluated, or assessed regarding use of dual mechanical barrier systems in gas storage wells.

2.38.1 Response 6.a.

Blade considered API RP 1171 titled "*Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs*" [4] that was published in September 2015. However, API RP 1171 does not require dual mechanical barrier in gas storage wells.

Blade also considered ISO Technical Specification 16530-1, *Petroleum and Natural Gas Industries-Well Integrity Life Cycle Governance* [5] that does discuss the need for multiple barriers and redundancy to achieve a high level of reliability. However, ISO 16530-1 was published in 2017.

2.39 Question 6.b.

Produce any and all DOCUMENTS related to any INDUSTRY STANDARDS identified in response to Request 6(a) above.

2.39.1 Response 6.b.

API RP 1171 is available on the API website. ISO 16530-1 is available on the ISO website.

2.40 Question 6.c.

For each of the INDUSTRY STANDARD(S) identified in response to Request 6(a) above, describe the reason(s) why BLADE evaluated the INDUSTRY STANDARD(S)

2.40.1 Response 6.c.

An outcome of the RCA process was that a root cause of the release of hydrocarbons was the lack of a dual mechanical barrier system, as discussed in the Blade Report on page 233—Section 5.3.1.

Therefore, Blade considered and assessed API RP 1171 and ISO 16530-1 to determine industry practices for dual barrier requirements.

2.41 Question 6.d.

Identify any and all LAW(S) that YOU considered, evaluated, or assessed in connection with the above statement.

2.41.1 Response 6.d.

Blade reviewed the October 2015 version of the *California Statutes and Regulations for Conservation of Oil, Gas, and Geothermal Resources* [1] as described in the Blade Report on pages 197 – 199—Section 4.6.1.

2.42 Question 6.e.

For each LAW(S) that YOU evaluated in preparing the BLADE REPORT identified in response to Request 6(d) above, state YOUR understanding as to whether SoCalGas complied with the LAW(S).

2.42.1 Response 6.e.

Based on Blade's technical review, no requirements were identified for dual mechanical barriers for gas storage wells in the October 2015 version of the *California Statutes and Regulations for Conservation of Oil, Gas, and Geothermal Resources* [1].

2.43 Question 6.f.

For each LAW(S) identified in response to Request 6(d) above, describe the reason(s) why BLADE evaluated the LAW(S).

2.43.1 Response 6.f.

An outcome of the RCA process was that a root cause of the release of hydrocarbons was the lack of a dual mechanical barrier system in the wellbore, as discussed in the Blade Report on page 233—Section 5.3.1.

Therefore, Blade evaluated the regulations to determine if regulations were in place prior to the SS-25 leak that required a dual mechanical barrier system for gas storage wells.

2.44 Question 7.

With regards to YOUR statement in the BLADE REPORT, at p. 238, that "[t]he root causes for the uncontrolled release of hydrocarbons for 111 days from SS-25 were . . . The lack of a well-specific well-control plan that considered transient kill modeling or well deliverability," please respond to the following questions:

2.45 Question 7.a.

Identify and describe any and all INDUSTRY STANDARD(S) that YOU considered, evaluated, or assessed related to well-specific well-control plans that consider transient kill modeling or well deliverability.

2.45.1 Response 7.a.

Although there are many references in the open literature, Blade considered the following as part of the RCA:

- API RP 1171, *Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs* [4] (published in September 2015)
- *Advanced Blowout and Well Control* [6] reference book
- *NORSOK Standard D-010 Rev 4, June 2013, Well Integrity in Drilling and Well Operations* [7]

2.46 Question 7.b.

Produce any and all DOCUMENTS related to any INDUSTRY STANDARDS identified in response to Request 7(a) above.

2.46.1 Response 7.b.

These documents are available for purchase online.

2.47 Question 7.c.

For any INDUSTRY STANDARD(S) identified in response to Request 7(a) above, describe the reason(s) why BLADE evaluated the INDUSTRY STANDARD(S).

2.47.1 Response 7.c.

An outcome of the RCA process was that a root cause of the release of hydrocarbons was the lack of a well-specific well-control plan that considered transient kill modeling or well deliverability, as discussed in the Blade Report on page 233—Section 5.3.1.

Therefore, Blade considered API 1171, NORSOK Standard D010 and *Advanced Blowout and Well Control* book. API RP 1171 discusses industry practices for a blowout contingency plan. NORSOK Standard D010 discusses kill rate simulation. The *Advanced Blowout and Well Control* book includes a discussion on dynamic kill operations and using friction to control the bottom hole pressure to kill the well.

2.48 Question 7.d.

For any INDUSTRY STANDARD(S) identified in response to Request 7(a) above, describe how long before the October 23, 2015 leak they were published or otherwise made available.

2.48.1 Response 7.d.

API RP 1171 was issued in September 2015.

The book *Advanced Blowout and Well Control* was published in 1994.

NORSOK Standard D-010 Rev 4 was updated in June 2013.

2.49 Question 7.e.

Identify any and all LAW(S) that YOU considered, evaluated, or assessed in connection with the above statement.

2.49.1 Response 7.e.

Blade reviewed the October 2015 version of the *California Statutes and Regulations for Conservation of Oil, Gas, and Geothermal Resources* [1] as described in the Blade Report on pages 197 – 199—Section 4.6.1.

2.50 Question 7.f.

For each LAW(S) that YOU evaluated in preparing the BLADE REPORT identified in response to Request 7(e) above, state YOUR understanding as to whether SoCalGas complied with the LAW(S).

2.50.1 Response 7.f.

Based on Blade's technical review, no requirements were identified for well-specific well-control plans that considered transient kill modeling or well deliverability in the October 2015 version of the *California Statutes and Regulations for Conservation of Oil, Gas, and Geothermal Resources* [1].

3 Nomenclature

3.1 Abbreviations and Acronyms

Term	Definition
API	American Petroleum Institute
Blade	Blade Energy Partners
ISO	International Standards Organization
NACE	National Association of Corrosion Engineers
NORSOK	Norsk Sokkels Konkurranseposisjon (a Norwegian Standards Organization)
RCA	Root Cause Analysis
SoCalGas	Southern California Gas Company

4 References

[1] State of California, "California Statutes and Regulations for Conservation of Oil, Gas, & Geothermal Resources," 2015.

[2] NACE International, "Application of Cathodic Protection for External Surfaces of Steel Well Casings (NACE SP0186-007)," 2007.

[3] American Petroleum Institute, "API RP 585 Pressure Equipment Integrity Incident Investigation," Washington, DC, April 2014.

[4] American Petroleum Institute, "API RP 1171, Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs," Washington, DC, September 2015.

[5] ISO, "Petroleum and natural gas industries-Well integrity-Part 1: Life cycle governance," 2017-03.

[6] R. D. Grace, Advanced Blowout and Well Control, Houston: Gulf Publishing Company, 1994.

[7] Standards Norway, "NORSOK Standard D-010, Well Integrity in Drilling and Well Operations, Rev 4," June 2013.

Ex. I - 13

Response to Data Request

Blade Response to SED Data Request

Prepared for:
Mr. Darryl Gruen

Purpose:
Blade response to the SED Data Request SED DR-49.

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1 Background

The California Public Utilities Commission Legal Division issued Data Request No. SED DR-49 to Blade Energy Partners (Blade) on December 5, 2019.

The data request is related to the Prepared Testimony of Amy Kitson on Behalf of Southern California Gas Company, dated November 22, 2019, at page 3, lines 1 through 14, and is replicated here verbatim for reference:

> **Solution 6: Conduct a Casing Failure Analysis**
>
> This mitigation/solution has already been implemented. The Blade Report incorrectly asserts that SoCalGas did not investigate the causes of previous casing failures. In order to remediate a leak discovered in any gas storage well, SoCalGas necessarily had to analyze and diagnose the issue first, before repairing it. In describing Solution 6, the Blade Report states that "casing failures need to be formally investigated." [Footnote 3, referencing Blade Report at p. 232] The Blade Report fails to recognize, however, that a "formal investigation" of the type Blade appears to envision would likely entail a level of examination that would not be feasible for an active well, nor necessary. While Blade was able to cut, extract, and thoroughly examine the casing at well SS-25 because there were plans to abandon the well, it is not feasible for SoCalGas to perform the same level of failure analysis on active gas storage wells. Further, although the SS-25 failure occurred at a relatively shallow depth, even Blade experienced difficulty cutting and extracting the casing. For casing failures thousands of feet belowground, operational issues may inhibit the cutting and extracting of casing.

The SED questions related to the Prepared Testimony are included verbatim followed by the Blade responses.

2 Questions and Responses

2.1 Question 1

Does Blade agree with, or disagree with any portion or all of the statement that, "The Blade Report incorrectly asserts that SoCalGas did not investigate the causes of previous casing failures."?

2.1.1 Response 1

Blade disagrees with the statement.

2.2 Question 2

Please provide an explanation in support of Blade's answer.

2.2.1 Response 2

Data gathering and a review of the data for the RCA that Blade conducted for the SS-25 casing failure determined that numerous casing failures [1] had occurred throughout the life of the Aliso Canyon field. SoCalGas communicated to Blade that any documents, reports and analysis related to failures would be contained in the well files. Blade reviewed numerous well files for wells with casing failures and did not find documentation of failure analysis.

The following are types of questions and analysis that should be considered as part of a failure investigation (whether the casing can be recovered or not):

- Is the corrosion on the ID or OD based on inspection log data?
- What is possibly causing corrosion? Modeling and assessment of water sources may be adequate to understand the problem.
- Was the failure in the casing body or is it in the connection? A camera run may reveal the nature of the failure. This may enabled an interpretation of the failure.
- Is the failure an isolated event or potentially a systemic issue? Are mitigating steps required?

However, if the casing can be recovered because it is parted shallow or the failure is shallow, then additional laboratory work can be conducted to develop a hypothesis on the causes of failure. There were cases where casing (failed or otherwise) were recovered, however no analysis reports were found in the well files.

There was no indication that failure analysis had been completed for any of the failures. Blade did not locate any such information in any of the well files that it examined in some detail.

Two of the wells (Frew 3 and FF-34A) had underground blowouts that were successfully controlled and repaired without difficulty. The Blade RCA Team was interested in understanding details regarding these two casing failures to determine if the failures were one-off or if there were systemic problems that may affect other wells in the field, and if any failures were similar to SS-25. No documentation of any failure analysis was available in the Frew 3 and FF-34A well files.

Blade wanted to confirm that failure studies or failure analyses reports were not overlooked. During the multi-year RCA process, Blade made several requests for information that provided evidence that a study or investigation was done by SoCalGas to understand the cause of casing failures.

The following are examples of the Blade information requests and SoCalGas responses:

1. Data Request February 18, 2018. This request was related to information collected as part of the storage integrity management program (SIMP) casing/integrity program. The request specifically asked for ". . . all daily reports, failure reports and documentation related to the failure analysis".

   SoCalGas responded with a list of wells, daily operational reports, and a Schlumberger casing integrity evaluation report (Figure 1). No documentation that shows failures were analyzed or studied was found in the well files.

   Blade was interested in the SS-44A well that reported defects in the surface casing and a longitudinal split in the production casing. The documents provided in the response from SoCalGas are included in Appendix A—Data Request February 18, 2018, SS-44A SoCalGas Response.

Question 2:

Have there been instances of casing with longitudinal or circumferential through wall defects identified by logs or visual inspection? If so, please provide the well name, the description of the failure, casing size, casing weight, casing grade, casing connection, etc. Also provide all daily reports, failure reports and documentation related to the failure analysis.

Response 2:

Well Name	Casing Size, Weight, and Grade	Casing Connection Type	% Wall Loss	Description
Standard Sesnon 44A	8 5/8", 36#, K55/N80	BT&C	N/A	Caliper log indicates potential surface casing through-wall defects at 90° and 225°
Standard Sesnon 44A	8 5/8", 36#, K55/N80	BT&C/LT&C	~100%	Visually identified a longitudinal split in the production casing
Mission Adrian 1B	8 5/8", 36/40#, N80	BT&C	~100% at 1590'	Longitudinal through-wall defect in production casing at 1590'
Porter 32	7", 23-29#, J55/N80	Speedfite	~100% at 5417'	Through-wall defect in production casing at 5417'.
Porter 44	7", 23-26#, N80/J55/S95	T&C	~100% at 4004'	Through-wall defect in production casing at 4004'
Porter 69A	9 5/8", 43.5-53.5#, N80	BT&C + LT&C	~100% at 7414'	Through-wall defect in production casing at 7414'.

For reports and documentation related to the failure analysis, see the following electronic documents.

Well Name	Bates Range
Standard Sesnon 44A	AC_BLD_0067777 – AC_BLD_0067784
Mission Adrian 1B	AC_BLD_0067591 – AC_BLD_0067625
Porter 32	AC_BLD_0067626 – AC_BLD_0067674
Porter 44	AC_BLD_0067675 – AC_BLD_0067719
Porter 69A	AC_BLD_0067720 – AC_BLD_0067776

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Blade-29 Response Letter.pdf

Figure 1: February 18, 2018, Data Request and Response

2. Data Request March 23, 2018, was a follow up to the data request on February 18, 2018, specific to the longitudinal split that was visually identified in the SS-44A production casing. Photographs and reports specific to the split, other than the daily reports already provided were requested. The information provided is included in Appendix B—Data Request March 23, 2018, SS-44A SoCalGas Response.

   SoCalGas responded that they were not aware of any photographs of the longitudinal split (Figure 2). SoCalGas sent daily operational reports. No failure analysis reports related to the cause to the failed casing were provided. The failed casing was made available to Blade for examination.

Question 1:

A response was provided, and it identified that in Standard Sesnon 44A a longitudinal split was visually identified in the production casing.

a. Are there any photographs of the split, that was visually identified, in SS 44A? Could you please provide them? Please provide any reports specific to the split, other than the daily reports already provided.
b. Is this longitudinal split from SS44A still available for examination? Could we have access to the split in SS44A?
c. Are the rest of the casing joints extracted from this well available for visual examination? Could you provide access to these joints?

Response 1:

SoCalGas provides the following response with respect to the SIMP casing integrity program.

a. SoCalGas is not aware of any photographs of the longitudinal split visually identified in the production casing of SS44A. Please see enclosed electronic documents with Bates range: AC_BLD_0067849 – AC_BLD_0067850 for additional reports related to the split in SS44A.

b. After extraction, the tubulars (tubing and casing) were transported to SoCalGas' vendor National Oilwell Varco (NOV) for storage. SoCalGas understands that the split in SS44A is located at NOV's facility in Bakersfield, California, and is available for examination.

c. See Response 1b.

Figure 2: March 23, 2018, Data Request and Response

Eleven months later on April 19, 2019, SoCalGas provided a Supplemental Response with photographs of the longitudinal split (Figure 3).

Question 1:

A response was provided, and it identified that in Standard Section 44A a longitudinal split was visually identified in the production casing.

a. Are there any photographs of the split, that was visually identified, in SS 44A? Could you please provide them? Please provide any reports specific to the split, other than the daily reports already provided.

Response 1:

SoCalGas provides the following supplemental response with respect to the SIMP casing integrity program.

a. For photographs of the longitudinal split visually identified in the production casing of SS44A, please see enclosed electronic documents with Bates range: AC_BLD_0067851 – AC_BLD_0067864.

Figure 3: April 19, 2018, Supplemental Response

3. August 24, 2018. Data Clarifications Meeting attended by CPUC, DOGGR-IT (DOGGR Investigation Team), SoCalGas, and Blade. Blade presented slides for discussion at the meeting. Figure 4 is an image of Slide 23.

Casing Integrity

- We have received many well files, and some of those wells had casing leaks and failures. If there was a further study of the failures or cause of such failures would it be part of the well file? If not would there be another repository of such information?

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Figure 4: August 24, 2018, Meeting, Slide 23

The verbal response from SoCalGas regarding Slide 23 during the meeting is summarized in the notes taken by Blade at the time. The Blade notes for this slide stated:

There is a excel file that Dan has collated around all the casing leaks/ruptures over the years since inception of the field for a SED data request. All leaks were included in Dan's excel. This will be shared with us. There appears to be no record of any failure analyses or reasons for the failures. The well file is a repository for the records.

Studies of casing leaks or problems were brought up again on the next slide (Figure 5).

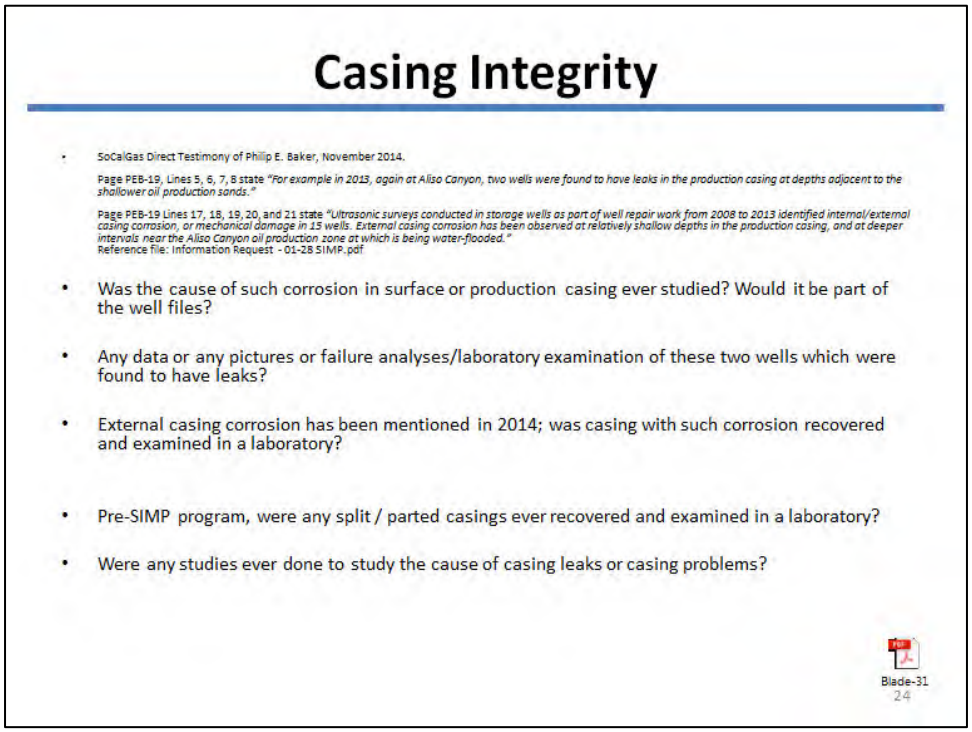


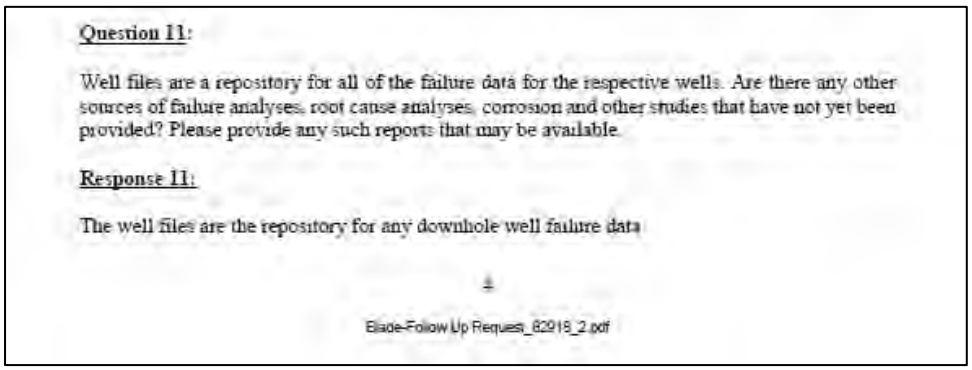
Figure 5: August 24, 2018, Meeting, Slide 24

The verbal response from SoCalGas during the meeting for Slide 24 is summarized in the notes taken by Blade at the time. The Blade notes for this slide stated:

> No knowledge on this topic. No shallow casing was ever recovered. Shallow casing problems have been few in the recent past.

4. Data Request August 29, 2018. This data request was a follow-up to the Data Clarification Meeting discussion held on August 24, 2018. The specific request was for any sources of failure analyses, root cause analyses, corrosion and other studies that have not yet been provided, and to provide any such reports that may be available. No failure analysis related information was found in the well files.

   On September 17, SoCalGas responded. No reports were provided as requested (Figure 6).



Question 11:

Well files are a repository for all of the failure data for the respective wells. Are there any other sources of failure analyses, root cause analyses, corrosion and other studies that have not yet been provided? Please provide any such reports that may be available.

Response 11:

The well files are the repository for any downhole well failure data

Blade-Follow Up Request_82918_2.pdf

Figure 6: August 29, 2018, Data Request and Response

5. Data Request December 18, 2018. This data request was related to a proposed study in the Frew 3 well file to determine if corrosion from fresh water could also affect other wells.

   On January 11, 2019, SoCalGas responded that the review program was not warranted because the leak was found to be deeper than earlier indications. Figure 7 shows an image of Question 3 and Response 3.

Question 3:

Refer to Frew-3 documents AC_BLD_0032691 through AC_BLD_0032692, Page 2, next to the last paragraph that states the following.

"If the cause of the leak is determined to be corrosion from the fresh water, a review program should be established to determine the number of wells that are also exposed to this action. Alternatives should then be considered as to the most effective solution to remedy the corrosion problem."

a. Was the work completed to determine if the cause of the Frew-3 leak was due to fresh water corrosion? Is so, please provide any study results or reports related to corrosion and the cause of corrosion.

Response 3:

Based on the cooling anomaly at +/- 1100', there was a concern that the leak was across the shallow sand and possibly caused by fresh water in the shallow sand. However, at the time of the workover recommendation, the exact type and location of the leak was unknown. It was recommended to run a casing caliper log to determine this information.

In January 1986, SoCalGas performed a workover of Frew 3 to repair the casing leak and ran both a Pengo Multi-Arm Casing Caliper Log and a Welex Casing Inspection Log to determine the type and depth of the leak. Both casing inspection logs identified that the hole in the production casing was at 3240', a depth considerably deeper than the shallow sand location. For the casing inspection logs, please see electronic documents with Bates range AC_BLD_0103355 through AC_BLD_0103367. For the workover history and daily well report, please see electronic documents with Bates range AC_BLD_0103348 through AC_BLD_0103354. Since the leak was not found at the shallow sand location, a review program of other wells was not warranted.

Following the two casing inspection logs, the production casing was squeeze cemented and pressure tested to 1000 psi, and the 2-7/8" tubing was replaced with a 5-1/2" inner string and 2-3/8" tubing.

Figure 7: December 18, 2018, Data Request and Response

2.3 Question 3

Does Blade agree with the statement that, "The Blade Report fails to recognize, however, that a 'formal investigation' of the type Blade appears to envision would likely entail a level of examination that would not be feasible for an active well, nor necessary. While Blade was able to cut, extract, and thoroughly examine the casing at well SS-25 because there were plans to abandon the well, it is not feasible for SoCalGas to perform the same level of failure analysis on active gas storage wells."

2.3.1 Response 3

Blade disagrees with the statement.

2.4 Question 4

If Blade agrees with the statement in question 3, please explain why.

2.4.1 Response 4

See Response 5.

2.5 Question 5

If Blade disagrees with any portion or all of the statement in question 3, please explain why it disagrees.

2.5.1 Response 5

Solution 6: Conduct a Casing Failure Analysis from the Blade Main Report, Section 5.3.1, Page 232, is replicated here for reference.

> **Solution 6: Conduct a Casing Failure Analysis**
>
> Despite numerous casing failures, no data were provided to indicate that failure causes were investigated. Casing failures need to be formally investigated so that their causes are identified and their implications are understood. Understanding and interpreting failures are critical to defining the propensity or risk of such failures field wide. Such analysis is an important part of any risk assessment. The cause may be straightforward, well specific, and easily mitigated. However, if the cause appears to systemic, or the potential consequences are serious, then a more comprehensive investigation is needed to evaluate the potential risks to other wells in the field so that the appropriate mitigation steps are taken. For example, failure investigation of casing OD corrosion in another well might have directed attention to SS-25 and other similar wells. Running an inner string or plugging a well are valid mitigations, but prior to such actions, the cause of the casing leak or failure should be understood. **The type of investigation should be commensurate with the risk and consequence of the failure, and should be part of the well integrity management system.**

As stated in Solution 6, the last sentence; "The type of investigation should be commensurate with the risk and consequence of the failure, and should be part of the well integrity management system." It is understood that all failures cannot be treated like SS-25, nor should they. The level of investigation depends on many things including the depth of the failure. It may not be feasible, practical, or necessary, to recover production casing from a deep leak. However, inspection and diagnostic tools are available to determine the nature of the failure, such as, a hole, corrosion—internal or external over a large or small area, location of a failure—pipe body or connection, etc. Such data should be integrated and analyzed to assess the possible causes and develop some hypothesis that can be used to evaluate other wells with failures. Once the failure has been evaluated and understood, the appropriate steps can be taken to determine the disposition of the well. The well can be repaired (inner strings, etc.) or plugged and abandoned if not repairable or if the well is no longer needed. SoCalGas did repair wells or plugged and abandoned wells after the failures were identified.

2.6 Question 6

With regards to the statement, that, "a 'formal investigation' of the type Blade appears to envision would likely entail a level of examination that would not be feasible for an active well. . .", what levels of examination are feasible for an active well that SoCalGas could have performed in Blade's opinion?

2.6.1 Response 6

This is addressed by Solution 7: Regulations Should Require a Level 1 (Per API RP 585) Analysis of All Failures in the Blade Main Report, Section 5.3.1, Page 232, replicated here for reference.

> **Solution 7: Regulations Should Require a Level 1 (Per API RP 585) Analysis of All Failures**
>
> API RP 585 *Pressure Equipment Integrity Incident Investigation,* discusses failure investigation of pressure equipment [2]. The Aliso Canyon wells are a form of complex pressure vessels. A Level 1 type analysis of

failures, as a minimum requirement, will identify the immediate causes of the failures or near misses and allow operators to understand the implications, if any.

Figure 8 shows the different levels of investigation as discussed in RP 585. A Level 1 investigation may be appropriate for most casing failures and can be done quickly with no disruption to field operations. API RP 585 was developed for Pressure Equipment Integrity Incident Investigation; however, Blade presents this as an option that could be applied to Gas Storage Well Integrity Management.

	Level 1 Investigations	Level 2 Investigations	Level 3 Investigations
Incident Characteristics	— Unexpected condition or damage found that if it had been allowed to progress would have led to loss of containment before the next scheduled outage or inspection interval. — Discovered PEI damage significantly beyond expectation but with no loss of containment or unit shutdown. — Small leaks (other than environmental fugitive emissions) from pressure equipment or joints that were easily contained. — Typically no fire, significant toxic release, injuries, or environmental damage would occur in a Level 1 incident.	— Leak from pressure equipment that resulted in or could have resulted in localized equipment damage, small to medium size release quantity, or small safety or environmental damage. — Unexpected pressure equipment failure from damage mechanisms or structural deterioration. — Unexpected pressure equipment damage or associated structural damage discovered that required equipment or unit shut down or immediate mitigation. — Repetitive Level 1 type characteristics in the same process or system.	Leak or rupture from pressure equipment that resulted in or could have resulted in significant process safety incident or environmental damage, equipment damage, large release quantity, or production loss.
Investigation Characteristics	Investigate using less structured analysis tools such as "What If" or "5-Whys." Uses evidence, judgment, and experience to identify causes.	Investigate using company or department causal factor identification or logic trees, seeking probable contributing and root causes.	Investigate using company structured root cause analysis (RCA) seeking to determine the deepest management system and cultural causes.
Team Makeup Recommended	Investigated by the PEI personnel from the affected area and trained in simple investigation techniques. Can be investigated by one person, possibly two, involve subject-matter experts (SMEs) as needed.	Leader would be someone from the affected area trained in investigation techniques. Team members would include one to three others of different disciplines from the area; include at least one PEI person on the team. Involve SMEs as needed.	Leader would be someone trained in structured RCA and from another area of the plant or another business unit. There would be at least three team members and possibly from different disciplines or groups, such as inspection, operations, process engineering, maintenance, or process safety. Appropriate SMEs should be included on the team.
Initiation	Within a few days.	Begin investigation as soon as practical (e.g. 1 to 2 days).	Begin freezing and collecting evidence as soon as practical (e.g. within a few hours).
Sponsorship	Supervisor of investigator (First Line Supervisor).	Department Head level (Second Line Supervisor).	Management with overall responsibility for Safety Health Environment for the site.

Figure 8: API 585 Inspection Levels

Failed casing in an active well can be analyzed using casing wall thickness inspection, downhole camera, and other diagnostic tools as discussed in Section 2.2.1 Response 2. This may provide data that can be used to interpret causes for the casing failure.

2.7 Question 7

Please provide an explanation for the answer in support of question 6.

2.7.1 Response 7

The discussion from Section 2.2.1 Response 2 is repeated here for reference.

The following are types of questions and analysis that should be considered as part of a failure investigation (whether the casing can be recovered or not):

- Is the corrosion on the ID or OD based on inspection log data?
- What is possibly causing corrosion? Modeling and assessment of water sources may be adequate to understand the problem.
- Was the failure in the casing body or is it in the connection? A camera run may reveal the nature of the failure. This may enabled an interpretation of the failure.
- Is the failure an isolated event or potentially a systemic issue? Are mitigating steps required?

However, if the casing can be recovered because it is parted shallow or the failure is shallow, then additional laboratory work can be conducted to develop a hypothesis on the causes of failure. There were cases where casing (failed or otherwise) were recovered, however no analysis reports were found in the well files.

2.8 Question 8

Does Blade have an opinion or opinions with regards to any other statement or statements in the passage?

2.8.1 Response 8

Yes

2.9 Question 9

If so, please provide such opinions, and the basis for them.

2.9.1 Response 9

Blade exhibited caution and took the time and care during the RCA casing extraction process to ensure that the evidence was unaffected by the extraction process itself.

A general statement regarding the RCA is that Blade completed the RCA based on data and information that was collected by Blade and data that was provided by SoCalGas. The RCA data was evaluated and analyzed independently by Blade. The RCA results were documented in the RCA Main Report and Supplementary Reports. Blade stands by the RCA reports that were provided to CPUC, DOGGR, and SoCalGas.

3 References

[1] Blade, "Analysis of Aliso Canyon Gas Storage Wells with Casing Failures," 2019.

[2] American Petroleum Institute, "API RP 585 Pressure Equipment Integrity Incident Investigation," 2014.

4 Appendix A—Data Request February 18, 2018, SS-44A SoCalGas Response

The following pages are images of the SoCalGas Response 2: referenced in Figure 1.

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION
DIVISION OF OIL, GAS, AND GEOTHERMAL RESOURCES

HISTORY OF OIL OR GAS WELL

Operator: Southern California Gas Company Field: Aliso Canyon County: Los Angeles

Well: Standard Sesnon 44 A Sec. 28, T03N, R16W, S.B.B.&M.

A.P.I. No.: 0403721455 Name: Tom McMahon Title: SIMP Project Manager

Date: 3/14/2018

Signature:

Address: PO Box 2300, SC9365, Chatsworth, CA 91313-2300 Telephone Number: 714-398-5020

History must be complete in all detail. Use this form to report all operations during drilling and testing of the well or during redrilling or altering the casing, plugging, or abandonment, with the dates thereof. Include such items as hole size, formation test details, amounts of cement used, top and bottom of plugs, perforation details, sidetracked junk, trailing tests, and initial production data.

Start Date	Ops this Report (DOGGR)
3/22/2017	HSM; It was determined to move here via Engineering. Rig is on SS-44B and will turn Rig around & equipment to rig up on SS-44A to abandon. Wait on SCG to remove sensor lines on SS-44 & SS-44B in order to install plates, for spotting in Rig. Continue to MIRU. Check psi on well - 0 . install BPV & remove tree. NU-BOPE and torque down. Test BOPE's 300 psi low/5000 high. GOOD. DOGGR: BOPE Inspection by- Mark Davis. Good. Note; Utilized BOI spotter for Traffic control
3/23/2017	HSM; 0 psi on well. R/U Donut puller F/Weatherford and back out dogs/Pull Hanger. Circulate sand off. TOOH w/Tbg. RIH w/retrieving tool and engage Pkr @ 2650' & TOOH and lay down. P/U Baker dummy seals and RIH w/kill string. Secure well.
3/24/2017	HSM; 0 psi on well. Continue to RIH w/dummy seal to engage straddle Pkr & wireline cut 3.5" Tbg. R/U wireline & RIH T/3933' and Cut W/RTC tool. Note; First attempt failed due to short in insulator. TOOH and repaired. Second attempt -Good. TOOH w/baker seal tool & L/D. P/U SC Retrieving tool and RIH w/123 jnts. Close in well same. Secure location.
3/27/2017	HSM; 0 psi on well. Latch into the Baker upper straddle Pkr @ 3933', and pull 42 K (21k over) and release Pkr. TOOH and lay down the 85 joints that were in well. Stand back the rest. P/U Baker Overshot (5 3/4") and RIH w/new kill string. Remove trailer & install Ensign pipe wrangler (tight location)-utilize traffic control flag man. Continue to RIH w/70 jnts and close in same. Secure location
3/28/2017	HSM; 0 psi on well. P/U 4 jnts and engage fish w/grapple @ 3933' and rotate on it. Pull up good. TOOH and lay down Fish (Baker Packer) with 1 and a half jnt of 3.5" Tbg. M/U a Baker/Bowen 1 1/2" Grapple & RIH by picking up 4700' of Tbg W/pipe wrangler. Stay above the 43" prong/plug fish @ 8700'. Close in same.
3/29/2017	HSM; 0 psi on well. Rotate over Fish (prong/plug of 43") w/ 5 K down on it, torqued up. TOOH easy. Pull T/BHA-No Fish. Make forward plan to use same BHA and reverse circulate while going over fish. (look for psi spike). RIH w/281 jnts of Tbg. Close in well same
3/30/2017	HSM; 0 psi on well. 4 stands above fish & will reverse circulate. RIH T/Fish and rotate while pumping over 43" plug/prong-fish. Pressured up to 550 psi. Stop pumping and TOOH of 281 jnts. Pull to Rig floor. NO FISH. NOTE: Get a hold of Curtis (Western Wire line) and he informed us that the PXN body is ALONG SIDE OF PRONG (2 separate runs when placed there) on top of sand for the Lok-Set RBP. Re-assessed the Fishing BHA, and recommended we run a 7.125" junk basket tomorrow with NO pumping to hopefully swallow both PXN/Prong. RIH w/ kill string and close in same
3/31/2017	HSM; 0 psi on well. Breakdown Baker fishing BHA to install 7.125" grapple. Wait on Baker to deliver grapple. Slip and Cut drilling line of 41'. P/U BHA and RIH w/10 stands of Tbg. HIGH Winds in Derrick- 2 hours. Continue T/TOOH w/239 jnts of Tbg. Shut in well. Secure location
4/3/2017	HSM; 0 psi on well. Cored over top of fish with no pump. Made 4.5' down. TOOH. No Fish. Ran kill string & close in same. NOTE: Baker is fabricating (In Shaffer) extension for Junk basket to reverse circulate up fish tomorrow.
4/4/2017	HSM; 0 psi on well. TOOH w/kill string & 4th Run-P/U Baker 7 3/8" Junk basket with 5' 6" extension. RIH and tag @ 8713' work down with NO pump using Ensign power swivel @ 65 rpm/1100 ft/lbs of torque. Rotated easy & got hard tag @ 8725', continue to rotate down to 8732' & stopped, rotate upward. TOOH & lay down extended junk basket. NO FISH. Discuss forward Ops; RIH w/same junk basket and pump this time. RIH w/140 stands and shut in well same.
4/5/2017	HSM; 0 psi on well. Continue to RIH w/30 stands of Tbg above fish. M/U power swivel & drop ball for basket catcher. Establish 1500 psi / 4 bbls/min. Work over fish @ 65 rpm F/8713' T/8743' with 110 ft/lbs of torque. Torqued up at the last foot.. Circulate hole volume (500 bbls) & TOOH. Lay Down basket. NO FISH. Discuss forward Ops. Run extended basket again. RIH W/150 jnts of Tbg and shut in same.
4/6/2017	HSM; 6th Run; Continue to RIH w/extended junk basket. Get over fish and R/U power swivel. Rotate over fish @ 65 rpm/ 2000 ft/lbs of torque/ 4.5 bbls/min. Got down to 8743' Note; Higher torque for sure. TOOH w/280 jnts of Tbg and lay down basket to check. NO FISH M/U 5 3/4" Overshot/bumper sub/1 jnt of Tbg/6 Tbg Jars & RIH. to above fish w/270 jnts. Close in same
4/7/2017	HSM: 0 psi on Open well (unloader open). 150 bbls to fill. Continue T/RIH w/overshot. Get above Fish and added 50 bbls more of fluid and got returns. Get over Fish @ 8742' and work over top of retrieving head of RBP, 6" down. Unset RBP w/Weatherford/3 attempts. GOOD. Circulated out gas out of well-clean. Pull up on Fish @ 52 K up (48 k up weight normally). Pull 40 stands very slowly with Fish on the hook. Shut in well same

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RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION
DIVISION OF OIL, GAS, AND GEOTHERMAL RESOURCES

HISTORY OF OIL OR GAS WELL

Operator: Southern California Gas Company Field: Aliso Canyon County: Los Angeles
Well: Standard Sesnon 44 A Sec. 28, T03N, R16W, S.B.B.&M.
A.P.I. No: 0403721455 Name: Tom McMahon Title: SIMP Project Manager
Date: 3/14/2018

Signature:

Address: PO Box 2300, SC9365, Chatsworth, CA 91313-2300 Telephone Number: 714-398-5020

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Start Date	Ope this Report (DOGGR)
4/10/2017	HSM; 0 psi on well. Pumped 100 bbls down annulus, no returns. Continue T/TOOH & @ 1388' BHA increased in drag. Pulled slowly as Rig was jumping. Installed 8 5/8" stub in BOP and pulled FISH TO RIG FLOOR. Lay Down the PXN plug (2 pieces) and the Prong that was on top of Weatherford Arrow set Pkr. (all elements in tact). M/U 8 5/8" all weight scraper and RIH T/6749' (just above PW Pkr). TOOH w/60 jnts of Tbg and shut in well same.
4/11/2017	POOH w/ scraper. Engaged & jarred packer loose f/ 8,734'. POOH w/ 120 jts. C.W.I.
4/12/2017	HSM; 0 psi on well. Added 75 bbls of polymer in well. Continue T/TOOH & only retrieving tool. NO FISH-(permatrieve Pkr). M/U 4" Baker-grapple spear and RIH, T/8756' & spear into Pkr. Pull 45 k over and jars sheared lugs. Wait for an hour. TOOH slowly. Have FISH & laydown. RIH w/kill string.
4/13/2017	HSM; 0 psi on well. Added 50 bbls of fluid to well. TOOH w/kill string. M/U Baker 3.25" spear & (2) 4 1/8" collars & RIH T/9075' and engage Otis PW Pkr. Work up 3 times w/jars and sheared out @ 72 k, 20 k over. Let relax and TOOH. Laydown Pkr. M/U 6 5/8" Scraper and bumper sub & RIH T/kill string and shut in same.
4/14/2017	HSM; 0 psi on well. Continue to RIH to bottom T/9376' (48') of FILL. DOGGR Notified. Attempt to reverse circulate-NO RETURNS. Pull up to 8822'. Close in same DOGGR Witness; Chris Gustafson
4/17/2017	HSM; 0 psi on well. Continue to TOOH & laydown scraper and removed 40' of fill in Tbg. M/U 5 5/8" Bit / bit sub / (2) 4-1/8" collars & RIH T/9376'. Turn on pump and work down through 3 bridged off areas. Worked down to 9424' & got partial returns @ 5 bbls/min @ 500 psi. Pulled up above liner top and Shut in same
4/18/2017	HSM; 0 psi on well. Add 50 bbls of fluid in well. RIH & tag bottom with No issues.TOOH and laydown BHA. On load with crane all Baker Fishing tools/Collars. RIH w/kill string & shut in well same. DOGGR; Mark Davis to witness and sign permit.
4/19/2017	HSM; 0 psi on well. Added 20 bbls of fluid & level @ 1210'. Pull kill string. R/U SLB loggers w/lubricator. Log 8 5/8" CBL/Nuetron log F/8822' (TOL) T/400'-fuid lvl. TOOH and make 2nd run F/9424' T/8822'. TOOH and R/D. Run kill string and secure well & location.
4/20/2017	HSM; 0 psi on well. Added 38 bbls of fluid and is Full. R/U DI-Drill Gyro service. Log F/9424' T/Surface with no issues. R/D Wireline. RIH w/279 jnts and close in same.
4/21/2017	HSM; 0 psi on well. HIGH WINDS clocked @ 38 mph at ground lvl. Stand by. Off load cement bin. Halliburton on stand by also.
4/24/2017	HSM; 0 psi on well added 80 bbls of fluid. Continue to RIH & tagged a bridge @ 9324'. Worked through and tagged bottom @ 9424' R/U Halliburton cementers & spot a 10 bbl cement plug @ 9422' & pull up 300' & repeat w/20 bbls cement plug. Pull up to 8613' & reverse out clean. Pull 3 stands & Shut in well same. Clean location. Slip & Cut 91' of Drilling line. CEMENT BLEND AS FOLLOWS: Mitsubishi Premium Cement/14.8 ppg/1.81 yeild/.05%-SA-10 /.25% SUPER CBL/.06Gal-SCR-100L/.30% HALAD (R)344/5%MICROLITE/.30%HALAD(R)-322/35% SS-200
4/25/2017	HSM; 0 psi on well. Added 6 bbls of fluid. DOGGR (Ernie Blevins) here T/witness tag @ 8613'. RIH T/9003' & tag solid (390') lower. R/U Cementers & pump a 20 bbls cement plug and polish off @ 8500'. Pull up and shut in well. CEMENT BLEND AS FOLLOWS: Mitsubishi Premium Cement/14.8 ppg/1.81 yeild/.05%-SA-10 /.25% SUPER CBL/.06Gal-SCR-100L/.30% HALAD (R)344/5%MICROLITE/.30%HALAD(R)-322/35% SS-200
4/26/2017	HSM; 0 psi on well. RIH & tag cement @ 8500'. Witnessed by Doggr, Ernie Blevins. 6 bbls to top off well. R/U Western Wire Line and shoot perf holes @ 8590'-8585' (4 spf) & TOOH, R/D. Establish a pump injection rate of 2 bbls/min @ 2000 psi of a total of 7 bbls. R/U Halliburton cementers/HSM & pump 21 bbls of Mitsubishi premium 14.8 ppg cement w/tail @ 8500'. @ 14.8 ppg/ 65 SXS 116 CUFT, pump 1 bbl of water spacer, pump 45 bbl t/displace.TOOH w/ 12 jnts setting tail @ 8210', pump 3 bbl to fill casing. Squeezed 4.5 bbl at 197 psi, shut down & wait 25 minutes & pump again @ 38 psi, squeezed 3 bbl at 167 psi. R/O Halliburton equipment. Pull 3 stands and shut in same w/No downward psi. CEMENT BLEND AS FOLLOWS: Mitsubishi Premium Cement/14.8 ppg/1.81 yeild/.05%-SA-10 /.25% SUPER CBL/.06Gal-SCR-100L/.30% HALAD (R)344/5%MICROLITE/.30%HALAD(R)-322/35% SS-200

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History must be complete in all detail. Use this form to report all operations during drilling and testing of the well or during redrilling or altering the casing, plugging, or abandonment, with the dates thereof, include such items as hole size, formation test details, amounts of cement used, top and bottom of plugs, perforation details, sidetracked junk, casing tests, and initial production data.

Start Date	Ops this Report (DOGGR)
4/27/2017	HSM; 0 psi on well. RIH w/3 stands and Tag @ 8310'. Doggr, Ernie Blevins here to confirm. Discuss Ops forward based off Cement Lyl. R/U Hallburton & pumped 24 obls of Deep blend/Premium Mitsubishi cement & displace 42 bbls w/polymer. Pulled up 7 jnts. & reverse out clean & shut in well. Secure location DEEP BLEND CEMENT BLEND AS FOLLOWS; Mitsubishi Premium Cement/14.8 ppg/1.81 yeild/.05%-SA-10 /.25% SUPER CBL/.06Gal-SCR-100L/.30%HALAD (R)344/5%MICROLITE/.30%HALAD(R)-322/35% SS-200
4/28/2017	HSM: 0 psi on well. RIH & tagged @ 7900' & witnessed by DOGGR-Mark Davis. R/U Hallburton cementers & test lines. Mix & pump 15 bbls of Premium Deep Mit. blend T/7550', and displace w/42 bbls of polymer. Pull up to 7650' & reverse out clean. Close in well. CHECK LOCATION/Valves. CEMENT DEEP BLEND AS FOLLOWS; Mitsubishi Premium Cement/14.8 ppg/1.81 yeild/.05%-SA-10 /.25% SUPER CBL/.06Gal-SCR-100L/.30%HALAD (R)344/5%MICROLITE/.30%HALAD(R)-322/35% SS-200
5/1/2017	HSM; 0 psi on well. Have meeting w/SDG & discuss fluid management at Rig site. TIH W/6 Jnts of 2-7/8" N-80 off of derrick tag @ 7650' Kristopher Gustafson w/DOGGR on location to witness tag. Waited on Hallburton Cementers. R/U Cementers & pump (2) plugs of 28 bbls each of Deep blend cement F/7650' T/6690' with no issues. Pulled up and reversed out. Then pulled high & shut in well. R/D Cementers & secure location. DEEP BLEND CEMENT BLEND AS FOLLOWS; Mitsubishi Premium Cement/14.8 ppg/1.81 yeild/.05%-SA-10 /.25% SUPER CBL/.06Gal-SCR-100L/.30%HALAD (R)344/5%MICROLITE/.30%HALAD(R)-322/35% SS-200
5/2/2017	HSM; 0 psi on well. DOGGR, Christopher Gustafson here to witness tag. Tagged lower @ 6751' (61' lower). R/U swivel and reverse circulate down T/6755', solid. R/O. General maintenance on Rig. R/U Hallburton Cementers & Pump (2) stages of plug. First with 27 bbls and pull up. Pump 2nd one of 29 bbls of Deep blend. Pull just above 5840' & reverse clean. Shut in same-secure location. DEEP BLEND CEMENT BLEND AS FOLLOWS; Mitsubishi Premium Cement/14.8 ppg/1.81 yeild/.05%-SA-10 /.25% SUPER CBL/.06Gal-SCR-100L/.30%HALAD (R)344/5%MICROLITE/.30%HALAD(R)-322/35% SS-200
5/3/2017	HSM; 0 psi on well. DOGGR: Chris Gustafson here to witness tag @ 5901' (51' lower), cement sample good. Perform Rig Maintenance. Wait on Hallburton cementers from SS-2 well for (4) hrs. R/U Hallburton & Tubing pressured up. Unable to clear. TOOH & laydown joint that was plugged. RIH w/killstring. Secure well and location.
5/4/2017	HSM; 0 psi on well. Laydown plugged Tbg. RIH T/top of cement plug & tagged @ 5588'. Reversed out to hard tag @ 5900' & circulate clean. ***HSM F/SS-25A with all personel on pipe handling protocal. R/U Hallburton cementers & pumped 30 bbls of Premium Mitsibishi Cement. Displaced w/27 bbls & pulled up T/5390' & reversed out clean. TOOH sideways w/40 jnts of tubing. (prep to move T/SS-25A). Shut in well same & secure location. DEEP BLEND CEMENT BLEND AS FOLLOWS; Mitsubishi Premium Cement/14.8 ppg/1.81 yeild/.05%-SA-10 /.25% SUPER CBL/.06Gal-SCR-100L/.30%HALAD (R)344/5%MICROLITE/.30%HALAD(R)-322/35% SS-200
5/5/2017	HSM; 0 psi on well. Continue to TOOH sideways w/30 jnts of Tbg. RIH w/Tbg in Derrick & do tag F/Doggr, Chris Gustafson Ok'd tag @ 5432'. after a soft tag @ 5396' (reverse circulated out 36'). Pulled up and reversed out clean. Left 174 jnts in hole & landed Hanger. Ran in dogs. ATTENDED SS-25A Meeting: On pipe extraction process. Rig Rig down floor/all support equipment. Load out Tbg. LEAVE ON BOPE: Double gate & Annular w/blind flange on DG and valve on the other. Rig out and load Accumulator/anaconda/Choke manifold. Pull out Rig and place alongside pad. (to be worked on over the weekend). Leave all plates & set up handrails around SS-44A well. Roper out Pump & shaker bin NOTE: Both tanks staying on location. Moving T/SS-25A Monday AM.
5/8/2017	HMS, MIRU, Tie rig down. Spot circulating pump. Rig up work floor, circulating pump. Accumulator hoses. Ready work floor.
5/9/2017	HMS . Open well. Completed safety check of rig and location. Pulled and laid down tubing hanger.RIH tag TOC @5432'. R/U Cementers. Pumped 2 x 32 bbl cement plugs. from 5432' - 4350'. Typ III cement. Pulled up circulated excess out. Pulled 4 stands. Secured well. EOT

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RESOURCES AGENCY OF CALIFORNIA
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DIVISION OF OIL, GAS AND GEOTHERMAL RESOURCES

HISTORY OF OIL OR GAS WELL

Operator: Southern California Gas Company Field: Aliso Canyon County: Los Angeles
Well: Standard Siesnon 44 A Sec. 28, T03N, R16W, S.B.B.&M.
A.P.I. No: 0403721455 Name: Tom McMahon Title: SIMP Project Manager
Date: 3/14/2018
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Start Date	Ops this Report (DOGGR)
5/10/2017	HMS: Open well. RIH tagged TOC at 4389'. Witnessed by Mr.Cliff Knight W/DOGGR. Pumped 2x 35 bbls balance plug f/4350' t/3801'. Secure well.
5/11/2017	Begin cement job as follows: Pump ahead w/9 bbls fresh water @ .70 bpm w/-6 psi, 37 bbls 14.8# type 3 cement @ 1.6 bpm w/29 psi, Displace w/1 bbl fresh water @ 1.2 bpm w/-10 psi, 13 bbls Polymer @ 2.8 bpm w/-10 psi T.O.C @ 2,642', POH w/21 jts 2-7/8" N-80. Pump 2 bbls fresh water @ 1.7 bpm w/36 psi, 37 bbls 14.8# type 3 cement @ 2.40 bpm w/40 psi, Displace w/1 bbl fresh water @ 1.0 bpm w/9 psi, 9 bbls Polymer @ 2.5 bpm w/-4 psi T.O.C @ 2,022' POH w/20 jts 2-7/8" N-80. Pump 2 bbls fresh water @ 1.5 bpm w/0 psi, 35 bbls 14.8# type 3 cement @ 2.0 bpm w/10 psi, Displace w/1 bbl fresh water @ 2.6 bpm w/-3 psi, 5 bbls Polymer @ 2.8 bpm w/-9 psi T.O.C @ 1,402' POH w/25 jts 2-7/8" N-80.
5/12/2017	RIH Tagged TOC at 1468' witnessed by Mr Cliff Knight W/DOGGR. Placed 36 bbl balanced cement plug f/ 1468' t/ 860' Pulled high Circulated well bore clean.
5/13/2017	RIH, Tagged cement plug high. Pulled high. Secure well. EOT
5/15/2017	HMS; POH, P/U DC's, Bit, Bit sub, Crossover. RIH tag cement. R/U power swivel. Drill out cement plug. Hang back power swivel. POH Stand back DC's. R/U W/L. Shot holes, Establish injection rate, RIH Set CICR.
5/16/2017	HMS; POH, RIH W/ Csg cutter. Cut csg.at 530' POH. N/D BOP , cut bolts on tbg head, Remove bolts. Replace bolts. Secure well EOT
5/17/2017	HSM. Remove well head. M/U WFD 5-3/4" spear w/7.882 grapple and engage into 8-5/8" casing and work up to 165K, could not get slips to unland Orginize location to make room for Baker Casing jacks, using TNT Trucking.Stand by for Baker Casing jacks. R/U Baker Casing jacks and pull on 8-5/8" casing and Could not get any movement. R/O casing jacks.Install well head to close in and secure well and location E.O.T.
5/18/2017	Run CBL log f/546 t/surface. Cut 8-5/8" csg at 200'. Attempt to pull with rig. Max 160k. No movement. R/U Csg jacks jack at 400k, moved csg 3.5'. R/D csg jacks Installed spool,BOP. Secure well. EOT
5/19/2017	Attempt to Jack top 200' of csg out of hole, max force with csg jacks 450k. Cut csg 17' down. pulled free. removed csg slips. L/D cut off joint, measured 17'. N/U riser and BOP. Secured well. EOT.
5/22/2017	RIH w/Spear and pack off. Attempt to circulate well while pulling with rig. Pulled 160k. No circulation or movement. R/U Csg jacks attempt to pull 8-5/8" csg. pulled 400k with 12" of movement. R/D csg jacks. Secure well.
5/23/2017	N/D BOP. R/U Baker casing jacks, RIH W/ WFd Spear set at 16'. Atempt to jack 183' of 8-5/8" csg out. Jacks stooped working. R/D Csg jacks. N/U BOP. Secure well. EOT.
5/24/2017	Cut 8-5/8" csg @ 100'. Pulled Csg to surface. Secured well EOT.
5/25/2017	L/D 8-5/8" csg. RIH W/ 7-5/8" bit ,cleaned out fill to 85'. POH, R/U and pumped 65 bbls of class 3 cement. Secured well. EOT
5/26/2017	Waiting on cement to harden.
5/30/2017	Cleaning out 8-5/8" csg.
5/31/2017	Clean out top of 8-5/8" cut off at 85' with 2-7/8" tbg and sawtooth collar. Cleaned out to 234' with 6-1/8" drill bit.RIH cleanned out to 118' with two string mills 5' apart.
6/1/2017	Coleaned top of 5-5/8 csg at 85'. POH Left mule shoe in hole. RIH W/ 6-1/8" bit Would not enter 8-5/8" csg. RIH W/2-7/8" sawtooth collar Would not enter top of 8-5/8" csg. RIH W/ Overshot 7-3/4" OD 5-1/2" Grapple stacked out at 123'. M/U Pilot mill RIH. Secure Well. EOT
6/2/2017	Milled top of 8-5/8 csg from 80.46' to 82.46'. RIHH W/ 7-3/4" Clean out bit, Cleaned out to 314'. Pulled high secured well.
6/5/2017	Attempt to pull 8-5/8" Csg with rig. No movement. R/U csg jacks attempt to jack out csg out with 550 k. No movement. RIH made cut at 148'. EOT.
6/6/2017	POH W/ Csg cutter. R/u Csg Jacks. pull cut csg from 56' to 138' POH L/D csg. RIH W 12" bit clean out to 138'.RIH W/ 7 3/4" bit. Clean out to 310' Pull above 8-5/8". EOT
6/7/2017	R/U Csg jacks. RIH Spear 8-5/8" @ 138'.
6/8/2017	Established circulation & cleaned out cement & formation f/ 164'-179' w/ 8.5# 60 vis. polymer. POOH. Laid down colars, bit sub & 10-5/8" bit. C.W.I.

OG103 (5/97/GSR/SM) SUBMIT IN DUPLICATE

AC_BLD_0067780

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION
DIVISION OF OIL, GAS, AND GEOTHERMAL RESOURCES

HISTORY OF OIL OR GAS WELL

Operator: Southern California Gas Company Field: Aliso Canyon County: Los Angeles
Well: Standard Sesnon 44 A Sec. 28, T03N, R16W, S.B.B.&M.
A.P.I. No.: 0403721455 Name: Tom McMahon Title: SIMP Project Manager
Date: 3/14/2018 Signature:
Address: PO Box 2300, SC9365, Chatsworth, CA 91313-2300 Telephone Number: 714-399-6020

History must be complete in all detail. Use this form to report all operations during drilling and testing of the well or during redrilling or altering the casing, plugging, or abandonment, with the dates thereof, include such items as hole size, formation test details, amounts of cement used, top and bottom of plugs, perforation details, sidetracked junk, sealing tests, and initial production data.

Start Date	Ops this Report (DOGGR)
6/9/2017	RIH w/ 2-7/8" open ended to 172 ' & broke circulation w/ 14 bbls. polymer. Rigged up cementers & broke circulation w/ 8 bbls. fresh water. Pumped 30 bbls of 14.6 cement. Lost returns. (Saw grey Wtr.) POOH. Closed blinds & squeezed 172 bbls of 14.6 ppg cement. Washed pumps & lines . Displaced 1 bbl. fresh water. C.W.I. 1st plug: 30 bbls. / 168 cf3/ 126 sks/ 794 gals water/ 19 bbls water to mix. Squeeze : 172 bbls/ 966 cf3 / 726 sks/ 4451 gals wtr / 105 bbls mix water Cement pumped : 14.6 ppg. Type 111 cement/ .3% bwoc EC-1/.8% bwoc FL-63/.4% bwoc CD-32 / 1 gal/ 100 sack FP-6L / 55.5% Fresh water. Final rate and pressure of 1BPM at 80 p.s.i. Final shut in pressure of 0 p.s.i.
6/12/2017	RIH Tag TOC at 14'. M/U clean out assembly, RIH attempt to reverse circulate, loss 24 bbls to formation. POH. Secured well. EOT
6/13/2017	RIH w/ 2-7/8" open ended to 172 .. Rigged up cementers & broke circulation w/ 5 bbls. fresh water. Pumped 4 bbls of 14.6 cement. POOH. Closed blinds & squeezed 1bbls of 14.6 ppg cement W/ fresh water. C.W.I. Cement pumped : 14.6 ppg. Type 111 cement/ .3% bwoc EC-1/.8% bwoc FL-63/.4% bwoc CD-32 / 1 gal/ 17 sacks 22 cu/ft FP-6L / 55.5% Fresh water. Final rate and pressure of 1BPM at 0 p.s.i. Final shut in pressure of 200 p.s.i.
6/14/2017	RIH Tagged TOC at 5. M/U Clean out assy. Cleaned out to 32'. RIH W/2-7/8" tbg reversed well clean. EOT.
6/15/2017	Continue cleaning out cement from 32' to 89'. Reversed well clean. EOT
6/16/2017	Continue cleaning out cement from 89' to 119'. Reversed well clean.
6/19/2017	Spotted 15 bbls 14.2 ppg Type III cement 4 bpm at 50 psi.. W/Csg valve open. Closed Csg valve pumped 2.5 bbls Type III cement .5 bpm at 50 psi. .Pressured up to 100 psi. CIP at 07:25. Type III Cement 76 sacks. A-10 293 lbs FP-6L 1 gal. Cello Flake 20 lbs.
6/20/2017	M/U Bit/Bitsub/drill collar/Power swivel. Tag TOC at 5' clean out cement to 43'. Circulate well clean. Secure well EOT
6/21/2017	Clean out cement from 43' to 179'. Secure well. EOT
6/22/2017	Cleaned out to top of 8-5/8 csg at 179'. RIH W/ 7-3/4" clean out assembly. Attempted to enter top of 8-5/8" csg. POH changer to Pilot mill, RIH cleaned out top of 8-5/8" csg. RIH W/ 7-3/4" bit cleaned out to 336'. POH. EOT.
6/23/2017	RIH W/ 5-1/2" Grapple. Not able to catch Mule shoe. Made two attempts. changed out grapples to 5-5/8". Made 3rd attempt. Not able to engauge fish. EOR.
6/24/2017	N/D BOP. Install CS/G. jacks. Attempt to pull 8-5/8" csg. 475k. No movement. N/D Csg. jacks. Install BOP. EOT
6/26/2017	Attempt to realse spear, POH installed 4-3/4" bumper sub. Continue to bump down. No movement. EOT
6/27/2017	Attempt to back of 4-3/4" DCs at bumper sub. back off at first Dc. R/U Wire line, RIH with back off shot. Backed off DCs. POH, Backed off at service break on bumper sub. Installed Annular preventer. Rigged up work floor. R/U WFD tongs. EOT
6/28/2017	M/U Overshot W/5-3/4" grapple, Bumper sub, 5 x 6-1/2" drill collars, RIH Enguage grapple, Bump down released spear. POH. L/D Spear,bumper sub, overshot assembly.
6/29/2017	R/U RIH w/ WFD 7-5/8" Mill Shoe, 1 5" 7-5/8" Wash pipe extention, 6 4-3/4" D.C's, 5 jts 2-7/8" N-80 8rd tbg. tagged fish @ 335'. Strip on 11" x 7-1/16"5M P.G.S.R head. Rig up WFD 2.5" Powerswivel, and W/O cement @ 335'-428'. R/O Powerswivel. Circulate well clean.
6/30/2017	Continue cleaning out from 428' to 812' with wash over assembly inside 8-5/8" csg. Pulled high circulated clean. Secure well and location.
7/5/2017	RIH tag at 812'. POH L/D Washover assembly, Found mule shoe stuck inside. (Fish out of hole). RIH cut 8-5/8" 36# csg at 393'. POH. N/D BOP, Installed Csg jacks. Not able to break cross over sub needed to run spear. R/D Csg jacks, N/U BOP. Secure well. EOT
7/6/2017	N/D BOP, Install Csg jacks. RIH W/Spear, enguage spear @ 190' attempt to pull 8-5/8" 36# csg, Pulled 600k. No movement. RIH cut 8-5/8" csg at 350'. RIH W/ Spear enguage spear at 190'. attempt to jack 8-5/8" csg, pulled 600k No movement. POH. R/D Csg jacks. N/U BOP. Secure well and location.
7/7/2017	N/D BOP. Install csg jacks. RIH Cut 8-5/8" 36# csg at 270 + -. RIH W/ 5-3/4" spear W/7.882" grapple. Engage spear at 160', R/U csg jacks, Csg started moving at 550K. Continue to work pipe out of hole. L/D 8-5/8" csg. Rig out csg jacks. Install BOP. EOT

OG103 (6/97/GSR/5M) SUBMIT IN DUPLICATE

AC_BLD_0067781

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION
DIVISION OF OIL, GAS, AND GEOTHERMAL RESOURCES

HISTORY OF OIL OR GAS WELL

Operator: Southern California Gas Company Field: Aliso Canyon County: Los Angeles
Well: Standard Sesnon 44 A Sec. 28, T03N, R16W, S.B.B &M.
A.P.I. No.: 0403721455 Name: Tom McMahon Title: SIMP Project Manager
Date: 3/14/2016
Signature:
Address: PO Box 2300, SC9365, Chatsworth, CA 91313-2300 Telephone Number: 714-399-5020

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Start Date	Ops this Report (DOGGR)
7/8/2017	RIH w/10 4-3/4" Drill collars. Begin to on 8-5/8" 36# casing @ 110K-650K, could not pull free. Attempt to release WFD Spear w/7.882" Grapple. Had problems releasing Spear, backed off collars. POH w/ 7 x 4-3/4" Drill collars. Remove Pacific Petroleum hydraulic jacks. Install 11"5M Double Gate BOP.
7/10/2017	RIH W/8-1/8" DCs, Screw in sub, Screw into spear, Work spear free, POH. M/U 8-1/8" Bit ,Bit sub, DCs. Clean out cement skin from surface to 211'. POH M/U 10-3/4" Pilot mill, RIH, Secure well.
7/11/2017	Remove Workfloor and handrails.Strip on 11" x 13-5/8"5M P.G.S.R.Rig up Workfloor and WFD casing tongs and equipment.Fill hole, Mill out 8-5/8" 36# casing w/WFD Pilot Mill from 211'-216'. Circulate well clean.Rig out and Hang back WFD 2.5" Powerswivel. Rig out WFD casing tongs, Workfloor, P.G.S.R.POH w/1 jt 2-7/8" N-80 8rd tbg. 6 4-3/4" Drill collars, WFD Pilot Mill.
7/12/2017	RIH w/WFD Pilot Mill, 6 4-3/4" Drill collars, 1 jt 2-7/8" N-80 8rd tbg to 211'. Strip on P.G.S.R. Rig up WFD 2.5" Powerswivel.Begin to Mill on 8-5/8" 36# casing @ 211'-216'. Circulate well clean, R/O Swivel.POH w/1 jt 2-7/8" N-80 8rd tbg, 6 4-3/4" D.C's, WFD Pilot Mill. Performed a BOP Drill w/ crew members @ 55 seconds, Discuss w/ crew. P/U RIH w/WFD Spear w/7.882" Grapple, 8 4-3/4" Drill collars and Engage into 8-5/8" 36# casing @ 216' and Attempt to pull free. Could not get casing to move. POH w/ 8 4-3/4" D.C's, Spear. RIH w/6 jts 2-7/8" N-80 8rd tbg to 211'. Rotate into 8-5/8" 36# casing. Rig up Poor Boy and Kelly hose, attempt to circulate and work tbg down, not make any hole.
7/13/2017	POH w/6 jts 2-7/8" N-80 8rd tbg. M/U RIH w/7-5/8" Bit, 6 4-3/4" Drill collars, 1 jts 2-7/8" N-80.R/U WFD 2.5" Powerswivel, M/U connection and Break circulation. C/O cement and fill from 211'-800'. Circulate well clean, R/O powerswivel.POH w/20 jts 2-7/8" N-80 8rd tbg, 6 4-3/4" Drill collars, L/D 7-5/8" Bit.RIH w/6 6" Drill collars, Laydown 6 6" Drill collars.
7/14/2017	RIH w/WFD Cutting Tool, 2 4-3/4" Drill collars, 6 jts 2-7/8" N-80 8rd tbg. R/U WFD 2.5" powerswivel and Perform 8-5/8" 36# casing cut @ 236' w/700 psi on mud pump.R/O WFD 2.5" Powerswivel. OH w/6 jts 2-7/8 N-80 8rd, 2 4-3/4" D.C's, Cutting Tool. P/U RIH w/WFD Spear w/7.882" Grapple, 2 4-3/4" Drill collars, 6 jts 2-7/8" N-80 8rd tbg and Engage " 36# casing @ 216'. Attempt to pull casing free, did not move casing.POH w/ WFD Spear and BHA. RIH w/ 12-1/4" Bit, 2 4-3/4" D.C's, 5 jts 2-7/8" N-80 8rd tbg and tag 8-5/8" 36# casing @ 211'. Rotate to verify casing. POH w/ tbg / Bit. Meet/Greet Western wireline. RSM and R/U equipment. RIH w/ 60 Arm Caliper Tool and log well @ 780'-Surface. R/O equipment.
7/17/2017	Remove tubing equipment and workfloor, Strip on P.G.S.R. R/U Workfloor and tbg equipment.P/U RIH w/WFD Pilot Mill, 6 4-3/4" Drill collars, 2 jts 2-7/8" N-80 8rd tbg @ 211'.R/U WFD 2.5" Powerswivel and Mill out 8-5/8" 36# casing @ 216'-218'. Circulate well clean. R/O WFD 2.5" Powerswivel, Strip off P.G.S.R Head. POH w/2 jts 2-7/8" N-80 8rd tbg, 6 4-3/4" Drill collars, WFD Pilot Mill.RIH w/2 4 3/4" Drill collars and POH L/D 2 4 3/4" Drill collars.
7/18/2017	RIH w/WFD Pilot Mill, 8 4-3/4" Drill collars to 218'. Spot in WFD 3.5 Powerswivel w/Pacific Petroleum Crane, Change out tbg elevators 2-7/8" to 3-1/2". R/U 3.5 Powerswivel and M/U connection. Mill out 8-5/8" 36# Casing F/218' T/248'. Circulate well clean, pull Powerswivel high.
7/19/2017	Continue to Mill out 8-5/8" 36# casing @ 248'-250'. Change out Powerswivel Safety valve.M/U Connection and Continue to Mill out 8-5/8" 36# casing @ 250'-278'. Circulate well clean, pull WFD 3.5 Powerswivel up high.
7/20/2017	Mill on 8-5/8" 36# casing @ 278'-285' Fell threw, Circulate well clean.Rig out WFD 3.5" Powerswivel. POH and L/D 2 4-3/4" Stick Drill collars. RIH w/2 4-3/4" Drill collars from derrick. "Performed a BOP Drill w/56 seconds, discuss drill w/ crew".P/U 2 4-3/4" Drill collars, tagged 8-5/8" 36# casing @ 292'. Change out elevators and R/U WFD 3.5" Powerswivel. Begin Reaming / Milling @ 292'-375', Circulate well clean. R/O Powerswivel,POH L/D 2 4-3/4" Drill collars, S/B 8 4-3/4" Drill collars, WFD Pilot Mill.Rig out WFD casing tongs, tbg equipment, workfloor.
7/21/2017	Rig up Workfloor and WFd casing tongs, P/U M/U 12-1/4" Tandem String Mill Assembly, 2 4-3/4" Drill collars. Strip on P.G.S.R head. Continue to RIH w/ 10 4-3/4" Drill collars, tagged @ 360'.Rig up WFD 3.5" Powerswivel, M/U connection and Attempt to Mill out cement / fill @ 360'. Could not make any hole, Circulate well clean and Rig out WFD 3.5" Powerswivel.POH w/12 4-3/4" Drill collars, Rig out workfloor and equipment, Strip off P.G.S.R head. POH and L/D WFD 12-1/4" Tandem String Mill Assembly.Install P.G.S.R head, Rig up workfloor and tbg equipment. P/U RIH w/7-5/8" Bit, 4-3/4" Bit sub, 2 4-3/4" Drill collars, 10 jts 2-7/8" N-80 8rd tbg. Roll up Doby Containment.
7/24/2017	Rig up WFD 3.5" Powerswivel and M/U connection, Break circulation. C/O Cement / Fill @ 360'-785'While making a connection, tubing became stuck. Work tubing @ 785'. Could not work free. Lost circulation.
7/25/2017	Rig out WFD 3.5" Powerswivel, Spool up and orginize hydraulic hoses.Meet/Greet Western Wireline. Rig up top sheave and hold safety meeting.RIH w/Western Wireline 1-7/16" Free point tool to 724'. RIH w/1-7/16" String Shot Tool and locate free point and Release from tbg @ 584'. R/O Western Wireline.POH w/23 jts 2-7/8" N-80 8rd tbg. Performed a Bop drill w/58 seconds, discuss drill w/ crew.Change over to 4-1/2" equipment. P/U RIH w/WFD Spear w/ 7.882" Grapple, 12 4-3/4" Drill collars. Change over elevators, R/U WFD casing tongs and M/U 4" Drill pipe pup jt. Engage and pull 8-5/8" 36# casing free @ 375'. POH w/ 12 4-3/4" Drill collars, WFD Spear, L/D 11' 8-5/8" CSG jt.P/U & RIH w/WFD 7-5/8" Mill Shoe, 2 7-5/8" Wash Pipe jts, X-over, 2 4-3/4" D.C's, 6 jts 2-7/8" tbg.

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AC_BLD_0067782

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION
DIVISION OF OIL, GAS, AND GEOTHERMAL RESOURCES

HISTORY OF OIL OR GAS WELL

Operator: Southern California Gas Company Field: Aliso Canyon County: Los Angeles
Well: Standard Sesnon 44 A Sec. 28, T03N, R16W, S.B.B.&M.
A.P.I. No.: 0403721455 Name: Tom McMahon (Person submitting report) Title: SIMP Project Manager (Position held by person signing report)
Date: 3/14/2018 (Month, day, year)
Signature:
Address: PO Box 2300, SC9365, Chatsworth, CA 91313-2300 Telephone Number: 714-398-5020

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Start Date	Ops this Report (DOGGR)
7/26/2017	R/U pumping equipment and break circulation. RIH w/16 jts 2-7/8" N-80 tbg, tagged sgnl spot @ 603'. POH w/4 jts, NOTE: Dragged out from 580'-530'.R/U WFD 3.5 Powerswivel & Attempt to break circulation, but lost 45 bbls to formation.R/O 3.5 Powerswivel & POH w/10 jts 2-7/8" N-80 8rd tbg. Strip off P.G.S.R head. Continue to POH w/2 jts 2-7/8 tbg, X-over, 2 jts 7-5/8" Wash pipe, 7-5/8" Mill Shoe.RIH w/ 23 jts 2-7/8" N-80 8rd tbg and tagged @ 684'.Dump 20 sacks of sand in 5 sack stages. POH w/8 jts 2-7/8" N-80 8rd tbg.
7/27/2017	RIH w/8 jts 2-7/8" N-80 8rd tbg, tagged @ 675'. POH w/22 jts 2-7/8" N-80 tbg, S.T.C.RIH w/WFD Cutting Tool, 2 4-3/4" D.C's. Change over 4-1/2" to 2-7/8" equipment. Continue to RIH w/16 jts 2-7/8" N-80 tbg.Rig up WFd 3.5" Powerswivel, Locate casing collars and Perform casing cuts in 8-5/8"36# casing @ 523', 480', 439' w/200 psi on mud pump." Performed a total of (3) 8-5/8"36# casing cuts". POH w/14 jts 2-7/8" N-80 tbg. Change over tbg equipment. Continue out w/2 4-3/4" D.C's, L/D WFD Cutting Tool.P/U & RIH w/WFD Spear w/7.882" Grapple, 12 4-3/4" D.C's, 14' Drill pipe pup jts and Engage into 8-5/8" 36# casing @ 393'. Start to Jar on 8-5/8"36# casing @ 393'. Could not pull free.POH w/12 4-3/4" D.C's, L/D WFD Spear.Rig out WFD Casing tongs, tbg tongs, X-over, workfloor.
7/28/2017	Remove 13-5/8" Double Gate BOP. Install Pacific Petroleum Hydraulic casing jacks.RIH w/ WFD Spear w/7.882" Grapple, 14 4-3/4" Drill collars & Engage into 8-5/8"36# casing @ 393'. Begin to pull on casing @ 100K-600K." WFD Spear Released.POH w/14 4-3/4" Drill collars, and Inspect WFD 7.882" Grapple. RIH w/WFD Spear w/7.882" Grapple, 14 4-3/4" Drill collars and Engage/Pull on 8-5/8"36# casing @ 413' @ 100K -600K. No movement.POH w/14 4-3/4" Drill collars, L/D Spear. RIH w/WFD Cutting Tool, 2 4-3/4" D.C's, Change over 4-1/2" to 2-7/8" euipment. Continue to RIH w/16 jts 2-7/8" N-80 tbg.Rig up WFd 3.5" Powerswivel, Locate casing collars and Perform casing cuts in 8-5/8"36# casing @ 523' w/200 psi on mud pump.R/O WFD 3.5" Powerswivel. POH w/ 16 jts 2-7/8" N-80 8rd tbg, 2 4-3/4" D.C's, Cutting Tool.Remove Pacific Petroleum Hydraulic casing jacks. Install 13-5/8" Double Gate BOP.
7/31/2017	Remove 13-5/8" Double Gate BOP. Install Pacific Petroleum Hydraulic casing jacks.RIH w/ WFD Spear w/7.882" Grapple, 14 4-3/4" Drill collars & Engage into 8-5/8"36# casing @ 393'. Begin to pull on casing @ 100K-450K." WFD Spear Released .POH w/14 4-3/4" Drill collars, and Inspect WFD 7.882" Grapple. RIH w/WFD Cutting Tool, 2 4-3/4" D.C's, 16 jts 2-7/8" N-80 to 393'. R/U WFD 3.5" Powerswivel and Perform 8-5/8"36# casing cut @ 523',480',439' w/200 psi on mud pump. R/O WFD Powerswivel.POH w/2 4-3/4" Drill collars, 16 jts 2-7/8" N-80 8rd tbg, L/D WFD Cutting Tool. RIH w/WFD Spear w/ 7.882" Grapple." WFD showed signs of failure, stand back collar and start in the AM.Remove Pacific Petroleum Hydraulic casing jacks. Install 13-5/8" Double Gate BOP. R/U Workfloor.
8/1/2017	Detail WFD Mill Shoe & Washpipe. Pick up and land 13-3/8" Bowl, Slips. Rig up Workfloor tbg equipment. WFD tbg tongs.Pick up RIH w/WFD 12-1/4" Mill Shoe, Washpipe, X-over, 4-3/4" Jar. R/O Workfloor, tbg equipment, WFD Tongs. Remove 13-3/8" Bowl, Slips & Strip on M/u 13-5/8" X 11"5M X-over/P.G.S.R head. Rig up Workfloor. RIH w/3 4-3/4" D.C's & L/D 3 4-3/4" Drill collars.Continue to RIH w/10 4-3/4" Drill collars and tagged @ 370'. Held a BOP drill w/55 seconds, discuss drill w/ crew members.Rig up WFD 3.5" Powerswivel & C/O Cement @ 370'-400', Circulate well clean.Rig out WFD 3.5" Powerswivel & POH w/5 4-3/4" Drill collars.
8/2/2017	RIH w/6 4-3/4" Drill collars. Rig up WFD 3.5" Powerswivel.Empty Cement cutting bin, Relocate cooling station, Fill kill tank w/ 8.5 Polymer.Break circulation (reverse) w/15 bbls 8.5 Polymer 120 Vis.Begin to Mill on 8-5/8"36# Casing @ 400. WFD 3.5" Powerswivel started to leak. Stand by for WFD to change out swivels. R/O Powerswivel. Change out & Rig up WFD 3.5" Powerswivel, Break circulation and Begin to Mill on 8-5/8"36# Casing @ 400'-405'." NOTE: Noticed that a fissure opended with polymer circulating fluid flowing from it. Amount flowed on ground less then 1/4 of a bbl. Rig out WFD 3.5" Powerswivel. POH w/12 4-3/4" D.C's, Rig out Workfloor & Strip off 13-5/8"X 11"5M X-Over / P.G.S.R head. R/U Workfloor & POH w/X-Over, Jars, 12-1/4" Washpipe, Mill Shoe.
8/3/2017	Meet\Greet Shlumberger wireline, Rig up top/bottom sheave's. RIH w/ CCL Logg Tool and Log well from 393'-Surface. Rig out wireline.Move out Pacific Petroleum cement bins, Load out move off WFD 3.5" Powerswivel.P/U RIH w/WFD 12-1/4" RBP, 14 4-3/4" Drill collars. Set WFD 12-1/4" RBP @ 350' L/D 2 4-3/4" D.C's, Dump 25 sacks of sand for 10'. Flush tbg w/ fresh water. Continue to POH & L/D 12 4-3/4" D.C's, RIH & L/D WFD 4-3/4" Jars, 12-1/4" Washpipe, Mill Shoe.Breakout & Load up pumping hose's, 4" hose's, Rig out mud pump and Load out WFD baskets.
8/4/2017	RIH w/12 jts 2-7/8" N-80 8rd tbg, tagged @ 340'. POH & L/D 22 jts 2-7/8" N-80 8rd tbg.Rig out tbg equipment, Workfloor. Remove 13-5/8" 5M BOP. Install 13-5/8" x 2-7/8" Flange.Load out rig eloment w/ Pacific Petroleum Crane.Wash out Rig Mud Pump and Move to bottom location, Clean location.

OG103 (6/97/GSR/5M) SUBMIT IN DUPLICATE

AC_BLD_0067783

5 Appendix B—Data Request March 23, 2018, SS-44A SoCalGas Response

The following pages are images of the SoCalGas data Response 1: referenced in Figure 2.

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION
DIVISION OF OIL, GAS, AND GEOTHERMAL RESOURCES

HISTORY OF OIL OR GAS WELL

Operator: Southern California Gas Company Field: Aliso Canyon County: Los Angeles
Well: Standard Sesnon 44 A Sec. 28, T03N, R16W, S.B.B.&M.
A.P.I. No. 04037221455 Name: Todd Van de Putte Title: Senior Storage Field Engineer
Date: 3/27/2018
Signature:
Address: PO Box 2300, SC9365, Chatsworth, CA 91313-2300 Telephone Number: 818-701-3339

History must be complete in all detail. Use this form to report all operations during drilling and testing of the well or during redrilling or altering the casing, plugging, or abandonment, with the dates thereof; include such items as hole size, formation test details, amounts of cement used, top and bottom of plugs, perforation details, sidetracked junk, casing tests, and initial production data.

Start Date	Ops this Report (DOGGR)
7/1/2014	Held safety meeting with crews. Unload BOP equipment. Rigged up PPC wire line unit ran in well to 8722 pulled prong. Ran in well to 8722 pulled plug body. Open well 0 psi tubing and casing rigged up and pumped 250 bbls with no fluid returns to surface secured well.
7/2/2014	Held safety meeting with crews open well 0 psi tubing 50 psi casing. Bleed down casing and pumped 75 bbls. tubing and casing 0 psi. Installed BPV nipped down production tree. Nipped up Class III BOP changed pipe rams to 2-7/8" and function test BOP. Rigged up working floor and tubing equipment secured well.
7/3/2014	Held safety meeting with crews. Rigged up WEA test unit test blind rams to 300 low and 5000 high for twenty minutes. (good) Tested pipe rams to 300 low and 5000 high for twenty minutes. (good) Tested Hydri to 300 low and 5000 high for twenty minutes. (good) Tested all control valves and choke manifold to 300 low and 5000 high for twenty minutes. (All test good). Rigged out test unit backed out hold down studs . Unlanded tubing attempt to release for packer at 8756' secured well.
7/7/2014	Held safety meeting with crews open well 0 psi tubing and casing pumped 50 bbls. Rigged up Tiger wire line made up free point tools. Ran in well to 8740' (free) ran in well to 8766' (no movement) Made up 2-7/8 cutter ran in well to 8734' correlated and cut 2-7/8" tubing. Rigged out wire line pulled out of well layed down 2-7/8" tubing to 3600' secured well.
7/8/2014	Held safety meeting with crews open well 0 psi tubing and casing pumped 50 bbls. Pulled out of well laying down 2-7/8" tubing layed sdown production equipment. Changed pipe rams to 3-1/2" made up 6.5 spear, bumper sub, jars, (2) 4-3/4" drill collars and intensifier. Measured and picked up 3-1/2" tubing to kill string at 2600' secured well.
7/9/2014	Held safety meeting with crews open well 0 psi tubing and casing pumped 50 bbls. Measured and picked up 3-1/2" tubing to top of patch at 3963'. Attempted to engag fish. Pulled out of well changed out grapple to 6.796". Ran in well to 3963 engaged fish jarred free. Pulled out of wel layed down fish (recovered top cone) Made up spear with 12" extension and stop, bumper sub ,jars ,(2) 4-3/4' drill collars and intensifier. Ran in well to 3910' secured well.
7/10/2014	Held safety meeting with crews open well 0 psi pumped 50 bbls. Ran in well too 3952' engaged fish jarred on patch moved up hole 10' came free. Pulled out of well layed down fish (recovered 20' patch left bottom cone in well.) Made up spear with 6.967 grapple, bumper sub , jars (2) 4-3/4" collars and intensifer. Ran in well to 3995' measured and picked up 3-1/2" tubing to 6570' secured well.
7/11/2014	Held safety meeting with crews open well 0 psi tubing and casing pumped 50 bbls. KCL. Measured and picked up 3-1/2" tubing to 8737' (top of cut off) Pulled out of well layed down fishing tools (no recovery). Made up 8-5/8" casing scraper and bumper sub ran in well 2550' secured well.
7/14/2014	Held safety meeting with crews open well 0 psi tubing and casing pumped 50 bbls. Ran in well with scraper to 8726' pulled out of well layed down scraper. Made up 6.75" die tap on 7-3/8" wash pipe ran in well to 5200' secured well.
7/15/2014	Held safety meeting with crews open well 0 psi tubing and casing pumped 50 bbls KCL. Rna in well with wash pipe to top of fish. Worked over fish pumped down annulus at 84 bpm work down to packer ay 674 6'. Pulled out of well layed down wash pipe (recovered bottom cone of patch) Made up 5-3/4" over shot with 2.875 grapple, bumper sub and jars. Ran in well to 3200' secured well.
7/16/2014	Held safety meeting with crews open well 0 psi tubing and casing pumped 50 bbls. Ran in well with fishing tools to top of fish at 8726'. Engaged fish worked free from packers. Pulled out of well layed down tools layed down cut off, top packer (10) joints 2-3/8" tubing ,sliding sleeve ,no/go nipple and bottom seals. Made up 8-5/8" casing scraper and bumper sub ran in well to kill string at 2600' secured well.
7/17/2014	Held safety meeting with crews open well 0 psi tubing and casing pumped 50 bbls. Ran in well with casing scraper to packer at 8749. Pulled out of well layed down scraper made up WEA 8-5/8" bridge plug. Ran in well to 8741 secured well.
7/18/2014	Held safety meeting with crews open well 0 psi tubing and casing pumped 50 bbls. Ran in well with RBP to 7734'. Set and released from RPE tested annulus to 500 psi for ten minutes (good) Dumped 8 sx sand pulled out of well layed down running tool. Rigged out tubing equipment and working floor serviced well head bolts secured well.
7/21/2014	Held safety meeting with crews open well 0 psi tubing and casing well standing full. Nipped down BOP nipped down tubing head and send in for repairs. Attempted to remove pack off unit (drawing shows automatic unit) Nipped up BOP and working floor secured well.
7/22/2014	Held safety meeting with crews open well 0 psi tubing and casing 0 bbls to fill. Rigged up Schlumberger wire line made up USIT/CBL tools. Ran in well to 8724' ran USIT/CBL to surface. Rigged out loggers secured well.
7/23/2014	Held safety meeting with crews work as directed labor only.
7/24/2014	Held safety meeting with crews open well 0 psi tubing and casing 0 bbls. to fill. Nipped down BOP nipped up and tested tubing head and primary seals. Nipped up BOP and working floor ran in well with kill string to 2400' secured well.
7/28/2014	Held safety meeting with crews open well 0 psi tubing and casing 0 bbls. to fill. Pulled out of well with kill string made up WEA test packer. Ran in well to 7026' set packer tested casing below packer at 700 psi for twenty minutes on test chart. (good) Filled annulus tested to 700 psi for twenty minutes (Bleed down to 100 psi in twenty minutes. Released packer pulled to 5037' set packer tested below packer to 700 psi for 5 minutes (good). fill annulus tested to 1100 psi for twenty minutes. (Lost 700 psi in twenty minutes) Released packer and pulled to 4800' secured well.

DG103 (6/97/GSR/5M) SUBMIT IN DUPLICATE

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AC_BLD_0067849

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION
DIVISION OF OIL, GAS, AND GEOTHERMAL RESOURCES

HISTORY OF OIL OR GAS WELL

Operator: Southern California Gas Company Field: Aliso Canyon County: Los Angeles
Well: Standard Sesnon 44 A Sec. 28, T03N, R16W, S.B.B.&M.
A.P.I. No: 0403721455 Name: Todd Van de Putte Title: Senior Storage Field Engineer
Date: 3/27/2018
Signature:
Address: PO Box 2300, SC9365, Chatsworth, CA 91313-2300 Telephone Number: 818-701-3339

History must be complete in all detail. Use this form to report all operations during drilling and testing of the well or during redrilling or altering the casing, plugging, or abandonment, with the dates thereof. Include such items as hole size, formation test details, amounts of cement used, top and bottom of plugs, perforation details, sidetracked junk, bailing tests, and initial production data.

Start Date	Ops this Report (DOGGR)
7/29/2014	Held safety meeting with crews open well 0 psi tubing and casing 0 bbls to fill. Pulled out of well to 3985' set packer and tested below packer to 700 psi (lost 40 psi in twenty minutes) tested annulus to 2000 psi (bled down to 0 psi in 5 minutes). Released packer and pulled to 3961' set packer and tested below packer to 700 psi. (lost 40 psi in twenty minutes) Tested annulus to 2000 psi (lost 1600 psi in six minutes) Pulled to 3925' tested below packer to 700 psi (good) Tested annulus to 2000 psi (Bled down to 16600 in six minutes found pressure on surface casing circulating at 1500 psi 1 bpm) Pulled to 1500 set packer pressured annulus with returns to surface pipe) Pulled to 1000' set packer pressured annulus with returns to surface pipe. pulled to 696' set packer pressured annulus with returns to surface pipe. Pulled to 500' set packer pressured annuus with returns to surface pipe. pulled to tested below to 700 psi (good) pressured annulus with returns to surface pipe. Pulled to 300' set packer pressured annulus with returns to surface pipe. Pulled to 125; attempted to set packer lug sheared on packer. Pulled out of well layed down packer made up 8-5/8" bridge plug ran in well to 2500' secured well.
7/30/2014	Held safety meeting with crews open well 0 psi tubing and casing 0 bbls. to fill. Ran in well with RBP to 4012' set RBP and dump 5 cu. ft. sand Pulled out well layed down retrieving tool made up 8-5/8" test packer. Ran in well to 3984' tested below packer to 2000 psi for twenty minute. (good) Released packer pull to 3658' set packer and tested to 2000 psi for twenty minutes. (lost 100 psi in twenty minutes at port collar) Released packer pulled out of well to 326' set packer tested below packer to 2000 psi for twenty minutes (good) Pumped into annulus with returns to surface pipe. Released packer and pull to 258' set packer pumped into annulus with returns to surface. Pulled to 197 set packer pumped into annulus with returns to surface. Pulled to 133' set packer pumped into annulus with returns to surface. Same results at 72', 24', 14', and 6'. At 5' tested below packer to 1000 psi for twenty minutes.(good) Released and layed down packer secured well.
7/31/2014	Held safety meeting with crews open well 0 psi tubing and casing 0 bbls. to fill. Rigged up Cameron and tested well head seals to 3600 psi for twenty minutes . Pumped in 8-5/8" casing with returns to surface pipe. Work as directed secured well.
8/1/2014	Work as directed labor only.
8/4/2014	Wait on orders work as directed labor only.
8/5/2014	Held safety meeting with crews open well 0 psi tubing and casing 0 bbls to fill made up retieving tool ran in well to 4000' secured well.
8/6/2014	Held safety meeting with crews open well 0 psi tubing and casing 0 bbls. to fill. Nippled up PGSR rigged up and reversed sand of RBP. Released bridge plug. Pulled out of well laying down 3-1/2" tubing layed down and loaded out bridge plug. Ran in well with 3-1/2" tubing to 4700' secured well.
8/7/2014	Held safety meeting with crews open well 0 psi tubing and casing 0 bbls. to fill. Layed down and loaded out 3-1/2" tubing. Layed down 4-3/4" drill collars changed pipe rams to 2-7/8" . Measured and piped up 2-7/8" tubing to 2500' secured well. Moved Baker tanks to Frew 3 and transfered fluids.
8/8/2014	Held safety meeting with crews open well 0 psi tubing and casing 0 bbls. to fill.Measured and picked up 133 joints. 2-7/8" tubing landed in tubing hanger. Nippled down BOP nippled up production tree secured well.

OG103 (6/97/GSR/5M) SUBMIT IN DUPLICATE

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WELL ACTIVITY REPORTS FOR FREW 3

DATE	ACTIVITY/REMARKS
6/14/84	(Continued) NOTE: When talking to the Shift Supervisor who worked the Sunday afternoon (6/10) the high annulus pressure was discovered on F-3, he said the well was taking far more gas than normal while on injection. He noted it sounded as if twice the volume of gas was being taken by the well. Flo-Log ran a temperature survey and noise log. Temperature ran at 100'/min from 500'-1500'. A 3 cooling anomaly was noted at 1160' and a smaller anomaly noted at 1100'. The noise log showed a large separation between the 200 Hz and the other three frequencies with all frequencies exited. The word used to describe the sound would be "crackling" or "popping". No disconcernable shifts in the frequencies were noted with the log being taken down to 3500'. Three different noise tools were used and all three were the same noise level. NOTE: The only hypothesis on the condition of the well would be the casing has a hole, split or is ported around 1100'. The subsequent feeding of the leak caused hydrates to form and back up all the way to the SSSV ports. This is supported by the "crackling" of the noise log which sounds like a very small amount of gas slowly moving and the inability of the temperature bombs to get below the ports at the SSSV thus showing some "plug" located there. Halliburton killed the well with 67# polymer. The first 100 Bbls was a 100+ cp viscosity pill followed by regular mix polymer using the constant tubing pressure method. The tubing pressure declined as normal to less than 100# with no casing pressure buildup. After approximately 100 Bbls had been pumped, the casing pressure began to decline from 1220#. This continued until 200 Bbls had been pumped when the tubing pressure finally kicked and the casing pressure was 800#. The remainder of the gas was vented as the kill proceeded. Once the casing pressure was zero (at approximately 350 Bbls, hole volume, 300 Bbls), returns were waited upon but never received. Eventually pumped a total of 580 Bbls of fluid into hole at 5 BPM with no returns. The tubing pressure did begin to rise slightly before we ran out of the fluid. Well was then shut-in. Both casing and tubing pressure was zero.

WELL ACTIVITY REPORTS FOR FREW 3

DATE	ACTIVITY/REMARKS
8/18/81	Pruett pulled SSSV, cost $515.00
8/19/81	Pruett pulled choke, cost $265.34
8/20/81	Ran temperature survey
8/31/81	Triangle ran sound log, cost $3,172.04
9/15/81	Otis ran SSSV, test OK, cost $1,235.00
10/27/81	Otis rigged up to pull SSSV, no complete
12/3/81	Otis set SSSV & BHC, will test on 12/4
12/4/81	Otis set SSSV & BHC, test OK
1/11/82	Pruett pulled SSSV
1/16/82	Pruett pulled BHC, blew-out and re-ran BHC
1/17/82	Pruett pulled BHC, blew-out second time
1/18/82	Sand testing
3/30/82	Ran temperature survey
10/20/82	Ran temperature survey, anomaly @ 7650'. Run A/A
12/16/82	Noise log run, no noise
6/8/83	Ran temperature survey, no anomaly
12/12/83	Ran temperature survey, no anomaly
4/2/84	Ran temperature survey, cooling anomaly at shoe
4/10/84	Ran detail temperature survey, confirms cooling from 6750'-7791' at shoe. A noise log will be run at high inventory due to low structural position of well.
6/10/84	Operations noted sudden jump in surface annulus pressure to 550#; repeated attempts to blowdown annulus were unsuccessful
6/11/84	Ran temperature survey which looked very abnormal; hottest temperature noted was around 80 F so assumed temperature bomb had malfunctioned.
6/13/84	MacCarlisle checked seals on wellhead, neither seal was leaking. Ran temperature survey which showed extreme cooling. Surface temperature was 38 and temperature @ 7750' was only 82. It should be noted both surveys (11th & 13th) could not be run through the tubing, but the survey run on 4/2/84 could go through; possible hydrates (?) all the way to SSSV ports. Continued trying to blowdown annulus, but it will rise back to 460# from 250# in minutes.
6/14/84	Baker set 500 Bbl tank on site for well kill. Test center came out and took sample of gas coming from annulus. Helium content on annulus was 560 ppm thus showing it was definitely Aliso gas and it was coming from a leak somewhere. Checked DA-2 (Del Aliso 2) which is in close proximity but only showed 24 ppm. No movement in that direction. Annulus pressure on F-4 increased abruptly from 30# to 180#. Looks like definite migration to F-4.

WELL ACTIVITY REPORTS FOR Frew 3

DATE	ACTIVITY/REMARKS
3/1/79	Pipe construction completed. Opened SSSV and put well on csg. W/D SIWHP 2560
3/30/79	Ran temperature survey
4/3/79	Archer-Reed rigged up and pulled separation tool. Latched onto SSSV but could not pull
4/9/79	Jarred on SSSV all day but could not pull. Ordered out braided wire unit for Monday
4/10/79	Archer-Reed removed SSSV
7/26/79	Ran temperature survey to BHC. Will have choke pulled and complete survey to bottom
7/27/79	Hanson Wireline pulled .770 BHC to complete temperature survey to bottom of well
7/31/79	Ran temperature survey to bottom of well.
10/24/79	Pruett ran BHP survey
11/2/79	Archer-Reed set BHC. Empty choke holder, ID 1.0
11/7/79	Ran BHP survey
11/20/79	Gurevich ran BHP survey
11/28/79	Pruett ran BHP survey
1/8/80	Ran 8 hr sand test. 1.0 BHC, SIWHP 2560, Pup 520; Pdn 520, Tup 69, Q 45
1/10/80	Archer-Reed pulled 1.0 BHC
1/14/80	Gurevich ran temperature & BHP survey. Archer-Reed ran scratcher
1/15/80	Archer-Reed ran XL sleeve shifter. Ran SSSV and separation tool tested valve as follows: S/I T 2560, S/I C 2590 1. Bled tubing to 1470, held good 2. Bled tubing to atmosphere 3. Bled casing to 1950, valve was closed 4. Pressure casing to 2400 5. Pressure tubing slowly to 2200, valve opened at about 1300. Test OK.
1/16/80	Ran sand test. 24-hours, 1.125 SSSV, SIWHP 2580; Pup 585; Pdn 585; Tup 67; Q 30
6/9/80	Archer-Reed pulled separation tool & SSSV. Cost $296.50
6/10/80	Gurevich ran temperature survey
6/20/80	Triangle ran noise survey. Survey shows some noise in WSO area of well. Will run R/A survey to verify. Cost #2185.00
6/24/80	Triangle attempted R/A survey. Panel problems in truck. Took to shop. Be back on Monday
7/7/80	Triangle ran R/A survey in shoe - WSO area of well. Cost $1700.10
10/20/80	Shut-in BHP survey
10/27/80	Pruett BHP survey
10/31/80	Archer Reed set 1.0 BHC. Cost $220.00
11/3/80	Pruett BHP survey
12/23/80	Archer-Reed set SSSV. Cost $370.50
3/20/81	Harry ran BHP
3/27/81	Harry ran BHP
6/4/81	Fred ran temperature survey
6/10/81	Fred ran temperature survey

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SOUTHERN CALIFORNIA gas COMPANY

INTEROFFICE CORRESPONDENCE

TO M. E. Melton FROM D. J. Anderson DATE Oct. 24, 1990

SUBJECT Radial Model of FF-34A Incident

BACKGROUND

On Monday evening, September 10, a downhole flowing condition was discovered in well Fernando Fee-34A. A pressure drawdown of 140 psig was recorded on the tubing/casing annulus, indicating the presence of a leak in the 8-5/8 inch casing. The leak was stopped when the well was killed at 10:20 a.m. the next morning. I developed a radial reservoir model to simulate gas migration updip from well FF-34A. The model was developed to determine the volume of gas lost at FF-34A, the gas distribution over time, and the time for gas to reach surface outcrops.

RESULTS

1. Based on the pressures recorded at well MA-5A, approximately 123 MMCF of gas was lost to a shallow zone in FF-34A. The zone of interest is a sequence of interbedded sandstones and shales over the interval 1500'-2000'. The shut-in pressures observed at MA-5A on September 11th and 13th compare closely with array pressures calculated in the model.

2. Gas breakthrough occurred in layer two on day six of the simulation (September 12). At six days, gas was detected in each radial segment in sector two of the model. Moving updip from FF-34A, the gas percentages found in sector two were 22.4%, 3.98%, 0.92%, 0.13%, and 0.04%. The gas saturation of 0.04% was found at a radius of 1570' from FF-34A. Assuming the shallow zone outcrops at a radius of 1500' or greater, six days is a good estimate of when gas might show up as seepage at the surface. However, the relative permeability at .04% is very low; in fact, it is probably below the critical gas saturation. Unless there are fractures or high permeability streaks, gas would not flow at high rates to the surface.

3. Figures 1 through 7 show the updip expansion of gas in layer two over forty-five days. Layer two is the most permeable layer in the model. The gas saturations remain low (0.1%) as gas percolates updip toward the surface. The highest gas saturations remain within two hundred feet of FF-34A. After forty-five days, the gas bubble expanded to a radius of 1200 feet, where saturations of 0.1% were detected.

64-F

DISCUSSION

Flowrate from NAPS

An estimate of the downhole flowrate for FF-34A was made using nodal analysis. The well mechanical showing wellhead pressures prior to and during the leak is shown in Figure 9. A flowrate of 35 MMCF/D was calculated using a flowing pressure of 2500 psig and a reservoir pressure of 3153 psig. A flowing wellhead pressure of 2460 psig was recorded in the field; however, 40 psig was added to the field pressure as a correction for depth. In the analysis, a backpressure exponent of 0.75 and a flow coefficient of 0.91 $MCFD/PSI^2$ were used. (Please see Table I.)

Initialization

A four-layer radial model was used to represent the zone of gas migration. Moving outward from the center of the model, it was divided into radii of 160', 420', 800', 1200' and 2100'. The model was designed with a 45° dip to the north. The shallow zone rock properties are as follows:

TABLE OF PROPERTIES

Property	Layer 1	Layer 2	Layer 3	Layer 4
Permeability	50 md.	75 md.	15 md.	15 md.
Thickness	55 ft.	20 ft.	50 ft.	100 ft.
Porosity	20%	24%	18%	18%

A total zone thickness of 225' was used based on the gas saturations discovered over the interval 1500'-2000' in well FF-34B. The model was initialized with an initial average pressure of 565 psia and 572 MMSTB of water in place. All layers were initialized with a gas/water contact depth of 400 feet. The date of initialization was September 6, 1990.

Simulation

The pressure history match was based on shut-in pressures observed on the number one annulus of MA-5A. To simulate the shallow well leak, gas was injected into FF-34A at a rate of 35 MMCF/D. Injection continued at this rate for three days (September 7-9). On the fourth day, the injection rate was reduced to 18 MMCF/D. By September 11, a total volume of 123 MMCF of gas had been injected. On this date, the maximum surface pressure recorded on MA-5A's

number one annulus was 760 psig. Assuming the annulus was filled with water, the surface pressure calculates to a zone pressure of 1309 psig. This compares closely with a grid block pressure of 1242 psig calculated by the model. On September 13, the shut-in surface pressure on the #1 annulus was 325 psig. The calculated zone pressure at this time was 835 psig. The model calculates a grid block pressure of 879 psig on this date.

The calculated pressures did not match the observed pressures on other surrounding wells (i.e., FF-34, FF-34B). I attribute this to the combined influence of variable fluid saturations and inter-bedded sands and shales that have irregular permeability patterns.

Wells FF-34, FF-34B, MA-3, MA-4, and MA-5A were produced at low gas rates (50-100 MCFD) to simulate the effect of surface blowdown and venting through fractures. The well locations are shown on Figure 8. A water producing well was completed updip at a radius of 1570' from the gas injection well. The water well was produced at a rate of 50 STB/D to simulate the surface outcrop.

DJA:ll
Attachment (see attached envelope)

cc: N. W. Buss
File AC1103

Ex. I - 16

History of Oil or Gas W.

OPERATOR GETTY OIL COMPANY FIELD ALISO CANYON FIELD

Well No. SFZU P-12, Sec. 27, T. 3N, R. 16W, S.B. B. & M.

Date July 16, 1970 Signed Carl G Nelson

P.O. Box 811, Ventura, Calif. 643-2154 Title Agent

(Address) (Telephone Number) (President, Secretary or Agent)

It is of the greatest importance to have a complete history of the well. Use this form to report a full account of all important operations during the drilling and testing of the well or during re-drilling, altering of casing, plugging, or abandonment with the dates thereof. Be sure to include such items as hole size, formation test details, amounts of cement used, top and bottom of plugs, perforation details, sidetracked junk, bailing tests, shooting and initial production data.

1/21/70	California Production Service moved in and rigged up to locate and repair a suspected hole in the casing.
1/22	Circulated down 6 5/8" casing and out 9" casing to sump. Recovered 20 barrels of oil. Squeezed 30 barrels salt water down tubing. Pulled choke from 6488' and circulated bottoms up. Removed tree and installed B.O.P.E. Pulled tubing and packer. Ran 6 5/8" fullbore and tested for leaks from 1041' to surface; 2305' to surface; 3377' to surface and 4543' to surface. Found leak between 3376' and 4553'.
1/23	With fullbore set at 4553' squeezed 30 barrels salt water into formation. Circulated hole free of gas. Located hole in 6 5/8" casing at 3634'. Pulled out with fullbore. Made up 4 3/4" retrievable bridge plug. Set plug at 6014'. Pulled tubing. Ran 6 5/8" fullbore to 4543'. Tested 4 3/4" bridge plug to 1500 psi, held O.K. Spotted 2 sax sand on top of bridge plug. Rechecked hole in casing - hole between 3634' and 3636'. Set fullbore at 3503' and pumped through hole in casing at 3 bbls/min. rate, 1000 psi. Mixed 40 sax Class G cement preceded with 5 cu.ft. water. Displaced with 5 cu.ft. water and 76 cu.ft. salt water. Stopped going and pressure went to 1500 psi. Could not move cement at 1500 psi. Backscuttled cement at 11:40 P.M. Pulled 15 doubles and shut job down for night.
1/24-26	Finished pulling fullbore. Ran 6 5/8" scraper and 5 5/8" bit. Tagged cement at 3504' with stringers to 3584'. Had hard cement from 3584' to 3600'. Had stringers from 3600' to 3634'. Ran down to swedge at 4622'. Closed rams and tested 6 5/8" casing to 1750 psi, held O.K. Pressure tested 9" casing to 1000 psi, held O.K. Pulled bit and scraper. Ran retrieving tool, tagged sand at 5985' and cleaned out to 6014'. Latched on to bridge plug. Backscuttled hole free of gas. Circulated corrosion inhibitor in salt water. Pulled tubing. Lost bridge plug coming out of hole. Reran tubing and latched on to bridge plug at 4800'. Pulled and recovered same. Hydrotested tubing in the hole. Set packer at 6564'. Removed B.O.P. and installed tree. Swabbed fluid to 3000'.
1/27	Swabbed fluid to 3500'.
1/28	Swabbed well from 4000'. Sand and mud cut becoming lower - mostly salt water with small showing of gas.
1/29	Tubing pressure 800#. Fluid level 2500'. Swabbed fluid level to 4500'.
2/6	Swabbed fluid from 2000' to 4500'. Well would not flow.
2/12	California Production Service moving in to swab well.
2/13	Moved in, could not swab well due to welding in vicinity of the well.
2/25	California Production Service moved in and rigged up. Found fluid level at 1700'. Swabbed to 4500'. Found fluid at 3500' between runs.
2/27	Found fluid level at 2200'. Swabbed fluid to 4000'. Last two runs had gas follow-up.

2/28-3/2/70	Ran swab, hit fluid at 1500'. Swabbed to 3500'. Ran swab, hit fluid at 1500' and swabbed to 4500'. Fluid level staying at 2000'. Prep. to swab - well had 400# tubing pressure. Flowed well to cellar with 400 psi through 14/64" surface choke. Put well in flowline. Well flowed all night at 400 psi through 13/64" choke.
3/3	Rigged down and moved out. Well flowing with 500 psi tubing pressure through 13/64" surface choke.
3/6	Flowed 12 BFPD; 33%; 8 BOPD.
3/17	Flowed 16 BFPD; 25%; 12 BOPD.
3/24	Flowed 8 BFPD; 8 BOPD.

FINAL REPORT

Casing Record:

16" 75# c 512'
11 3/4" 61# F&C 2310'
9" 45# c 4721'
WSO shoe 4721'*
4 3/4" 16# & 6 5/8" 26 & 28# c 6910'
WSO shoe 6910'
Cmtd. hole 3634-3636'
684'-3 1/2" 13.3# L 7548'
Pf: 6908-7548'
(2" x 60 M x 6 R x 6" C)
T.L.H. 6864'

*Witnessed and approved by D.O.G.

Tubing Record:

6487'	- 2 7/8", 8 RT, J-55 EU Tbg. (206 Jts)
1'	- 2 7/8" Otis Type X port collar at 6488'
61'	- 2 7/8", 8 RT, EU Tbg. (2 Jts)
1'	- 2 7/8" x 2 3/8" 8 RT Xover
6'	- 2 3/8" 8 RT N-80 pup jt.
7'	- 2 3/8" x 4 3/4" 16# KV-30 packer
1'	- 2 3/8" belled collar
6564'	- Overall

Ex. I - 17

FORM 103

SUBMIT IN DUPLICATE

STATE OF CALIFORNIA

DEPARTMENT OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

Area

History of Oil or Gas Well

OPERATOR GETTY OIL COMPANY FIELD ALISO CANYON

Well No. SFZU SS-14, Sec. 28, T. 3N, R. 16W, S.B. B. & M.

Date December 4, 1969 Signed Carl H. Nelson

P. O. Box 811, Ventura, Calif. 643-2154 Title Agent
(Address) (Telephone Number) (President, Secretary or Agent)

It is of the greatest importance to have a complete history of the well. Use this form to report a full account of all important operations during the drilling and testing of the well or during re-drilling, altering of casing, plugging, or abandonment with the dates thereof. Be sure to include such items as hole size, formation test details, amounts of cement used, top and bottom of plugs, perforation details, sidetracked junk, bailing tests, shooting and initial production data.

HISTORY

6/16/69 Killed well with 320 barrels salt water. Prep. to throw the derrick.

6/17 Threw the derrick.

6/18 California Production Service moved in and rigged up. Circulated well free of gas. Removed tree. Installed B.O.P. Measured out with tubing. Ran 6" bit and 7" scraper to T.L.H. Landed in tubing head. Shut down for the night. (Suspected leak in packing between 7" and 13 3/8" surface string.)

6/19 Circulated bottoms up. Mixed corrosion inhibitor and circulated around. Tagged top of liner hanger at 8062'. Pulled out. Removed B.O.P. and tubing head. Found hole in casing bowl and split in top of 7" casing. Repacked the casing bowl. Hydrotested in hole with 4500 lbs./inch. Total overall tubing in hole 9000' with Guiberson packer at 7998' and MM mandrel with dummy valve one joint above packer. Circulating bottoms up.

6/20 Circulated bottoms up. Pulled tubing. Ran and set Halliburton bridge plug at 7971'. Pulled up to 7260'. Installed KV-30 packer in string. Ran back down to 7400' (KV-30 at 240'). Set packer and tested bridge plug to 600 psi, held O.K. Pulled packer, tubing, and retrieving tool. Shut the well in.

6/23 Ran Dialog casing log. Logged 7" casing from 810' to surface. Cut 7" casing at 105' and recovered. Cut off 13 3/8" casing landing bowl. Welded on new Shaffer 13 3/8" casing landing bowl. Ran 7" casing with Bowen packer type casing patch. Latched on and set with 40,000 lbs. tension. Set slips, cut off and packed 7". Installed tubing head and B.O.P. Tested casing patch to 1000 psi. Held O.K. Ran tubing with Howco retrieving tool. Unset bridge plug. Circulated corrosion inhibited salt water. Pulled out. Ran and set packer at 7978'. ? Swabbed well to 5000'. Shut down for the night.

6/24 Swabbed well in. Well flowing, 8/64" surface choke, 750 psi tubing pressure.

6/25 Rigged down and moved out.

6/27 Flowed 24 BFPD; 20 BOPD.

7/3 Flowed 76 BFPD; 13%; 66 BOPD; 555 MCF.

7/7 Flowed 70 BFPD; 11%; 62 BOPD; 744 MCF.

7/30 Flowed 24 BFPD; 8%; 22 BOPD; 1329 MCF.

8/2 Flowed 28 BFPD; 7%; 26 BOPD; 708 MCF.

FINAL REPORT

CONFIDENTIAL

Casing Record

20" c 33'
13 3/8" 54.5# c 817'
7" 29, 26, 23# effec. to 8150'
(Window 8165'-8195')
Casing Bowl at 105'
1109' -5" 18# c 9171'
(Cmt. in liner at 9167')
WSO splice* and 4 h's 8889'*
Seg. 4 h's 9010'
G.P. 4 h/ft 8895-8947'; 8961-9000'; 9020-9118'; 9132-9165'
T.L.H. 8062'

*Witnessed and approved by D.O.G.

Junk Record

1. 716' - 7" ST'd (Rd. 1) 8150-8165'; Window 8165-8195'
ST'd (Rd. 1) 8195-8896'

2. 153' - 5" ST'd. (Rd. 1) 8863-9016'

Ex. I - 18

FORM 103
CALIFORNIA STATE PRINTING OFFICE

SUBMIT IN DUPLICATE

STATE OF CALIFORNIA
DEPARTMENT OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

History of Oil or Gas Well

OPERATOR TIDE WATER ASSOCIATED OIL COMPANY FIELD ALISO CANYON

Well No. Standard-Seamon 2-17, Sec. 26, T. 3 N, R. 16 W, S.B. B. & M.

Signed F. C. Foster
p

Date October 13, 1952 Title Agent
(President, Secretary or Agent)

It is of the greatest importance to have a complete history of the well. Use this form in reporting the history of all important operations at the well, together with the dates thereof, prior to the first production. Include in your report such information as size of hole drilled to cementing or landing depth of casings, number of sacks of cement used in the plugging, number of sacks or number of feet of cement drilled out of casing, depth at which cement plugs started, and depth at which hard cement encountered. If the well was dynamited, give date, size, position and number of shots. If plugs or bridges were put in to test for water, state kind of material used, position and results of pumping or bailing.

Date

1952

7/20 Swabbed 175 barrels of muddy water. Salinity at 4:00 PM, 492 grains per gallon. Fluid level 2000'. Pulled tester loose at 11:00 PM and found fluid level at 1500'. Water sample above tester, 554 grains per gallon.

7/21 Ran bit and cleaned out to 11,000'. Found sand bridge from 10,430' to 10,435'. Had good gas showing on ditch while circulating returns from 10,430'. Ran McCullough Neutron Log. Pls #1 found to be [illegible]

7/22 Hung 3-1/2" drill pipe at 9548' and plugged with 100 sacks Colton Hi-Temperature Cement. Final pressure 800#. Time 11:30 AM. B.J. Service. Located top of plug at 9234' after standing 6 hours. Ran McCullough magnetector and checked aluminum section at 8433' to 8523'. Started milling aluminum section at 8490'.

7/23 Milled aluminum section from 8490' to 8516'.

7/24 Found bottom of aluminum section at 8516'. Pulled up and started milling aluminum section at 8476' and milled to 8490'.

7/25 Ran 10-5/8" Baker scraper and scraped from 8476' to 8516'.

7/26 Ran Booth Ross whipstock on 3-1/2" drill pipe and set on stub of 7" casing at 8516' with tailpipe to 8531'. Cemented in place with 50 sacks of Colton Hi-Temperature Cement. Time 5:45 AM. B.J. Service.

7/27 Standing cemented. Located top of cement at 8438'.

7/28 Cleaned out cement from 8433' to 8507' and redrilled to 8535' with 6" bit.

7/29 Redrilled 6" hole from 8535' to 8669'. Ran Schlumberger electric log at 8663'. Hole following alongside 7" casing.

7/30 Hung 2-1/2" tubing at 8656' and plugged well with 100 sacks Colton Hi-Temperature cement. Final pressure 700#. Time 6:00 AM. B.J. Service. At 4:00 PM located top of cement at 8250'. Cleaned out to 8273' and lost circulation. Ran Halliburton squeeze tool and located hole in 7" casing at 5238'.

7/31 Set Halliburton squeeze tool at 4985' and pumped in 100 sacks Victor Hi-Temperature cement through hole at 5238'. Final pressure 400#. Time 8:30 AM. Halliburton Bulk Method. At 1:30 PM applied 1100# pressure without loss. Located top of cement at 4996' and cleaned out hard cement to 5256', then found stringers of cement to 5286'.

8/1 Cleaned out cement from 8278' to 8359'. Closed rams and applied 1250# pressure for 15 minutes without loss. Cleaned out cement from 8359' to 8330' and lost circulation. Ran Halliburton shoe squeeze tool on 3-1/2" drill pipe and set at 4955'. Displaced fluid easily with 800# pressure. Mixed 150 sacks of Colton Slow Cement and displaced with 227 cu. ft. mud. Final pressure 500# which bled to 0#. Time 6:00 PM. Halliburton Bulk Method.

8/2 Standing cemented. Located top of cement at 4955'.

Ex. I - 19

PORTER 47

DAILY DRILLING REPORT

3-29 Continued running tubing and 1" control line. Tested safety valve and control line through donut with 5000 psi for 45 minutes, OK. Landed tubing. Tore out BOPE and installed production head. Tested through test port with 4500 psi for 15 minutes, OK. Tested through unibolt against Shaffer donut plug with 4650 psi for 15 minutes, OK. Rigged up Otis wireline. Closed sliding sleeve at 6782'. Set No-Go plug at 8254'. Pressured tubing and set Otis hydraulic packers. Pulled No-Go plug. Tested top packer by pressuring annulus with 1140 psi for 15 minutes, OK. Opened sleeve at 6782'. Control line at 5000 psi for overnight test.

SEE SUPPLEMENT DATED 4-20-73

SEE SUPPLEMENT DATED 5-4-73

PORTER 47

DAILY DRILLING REPORT

3-23 No morning tour. Waiting on cement, continued running 4-1/8" bit and scraper, tagged cement at 7888' (60' high) drilled and cleaned hard cement 7888-8058' circulated from 8104' for one hour. Pressure tested from surface to 8126' with 1625 psi for 30 minutes, OK. Started out of hole with bit and scraper.

3-24 Continued pulling bit and scraper, ran retrieving tool and released bridge plug at 8126'. Ran in from 8126' to set bridge plug onbottom. Stopped at 8138'. Believe cement from squeeze at 8056' was pumped into liner below bridge plug through unsqueezed WSO holes at 8138'. Pulled bridge plug, ran 4-1/8" bit and 5" casing scraper. Tagged cement at 8138'. Drilled and cleaned out soft cement 8138-8200' and hard cement at 8283'. Drilled and cleaned out hard cement at 8297' to 8352'. All perforations cemented, circulated on bottom one hour. Started out of hole with bit and scraper.

3-26 Continued pulling bit and scraper. Rigged up Dresser-Atlas. Ran cement bond log 7900-8355', cement bond at top of S-4 questionable. Jet perforated four 1/2" holes at 8135'. Made up and ran Johnston tester and bridge plug in tandem, set bridge plug at 8158'. Pulled up and set test tool at 8062', tail to 8080'. Opened tool at 6:50 pm. Dead throughout one hour test. Pulled bridge plug and tester. Recovered 5' rise oily workover fluid, charts OK. WSO. Witnessed and approved by P. R. Wygle of the D.O.G.

3-27 Rigged up Dresser-Atlas jet perforated four 1/2" holes 8159-8189', 8200-8223', 8270-8276', 8330-8343'. Used 3-1/2" carriers and 11.0 gram charges. Made up and ran Baker Model "C" bridge plug and fullbore packer. Set bridge plug at 8242'. Pulled up and set fullbore packer at 8140'. Pumped into formation at rate of 0.8 barrels per minute at 2200 psi. Too tight for Halliburton Clay-Lok. Pulled bridge plug and fullbore.

3-28 Rigged up to run Otis packer, Page safety valve and 1" GST control line. Tested safety valve and control line connections with 4850 psi for 20 minutes, OK. Ran into 5623'. Tested control line and safety valve with 4975 psi for 30 minutes, OK.

PORTER 47

DAILY DRILLING REPORT

3-21 Installed BOPE on new tubing head. Used rig pump. Tested pipe rams and casing from surface to 6911' with 1650 psi for 15 minutes, OK. Made up Baker 5" fullbore packer and retrieved tool. Ran in and recovered bridge plug at 6911'. Reset bridge plug at 8126'. Pulled up and set fullbore at 8056'. Tested bridge plug and 5" casing at 8056-8126' with 1625 psi for 15 minutes, OK. Pulled up and set fullbore at 7486'. Tested 7486-8126', no good. Tested from surface to 7486' - inconclusive. Picked up 14' of pup joints to space out properly between collars. Set fullbore at 7816'. Tested 7816-8126', no good. Tested from surface to 7816' with 1700 psi for 15 minutes, OK. Set fullbore at 7943' and tested 7943'-8126', no good. Set full bore at 8007' and tested at 7008'-8126', no good. Set fullbore at 8038' and tested 8038-8126', no good. Tested from surface to 8038' with 1750 psi for 15 minutes, OK. Leak isolated between 8038-8056'; collar at 8052' with fullbore set at 8038'. Could not break down formation with 3100 psi surface pressure (approximately 6650 psi at hole). Collar leak indicated, with fullbore hanging at 8056'. Pumped in two sacks of sand. Pulled up and hung fullbore at 7864'. Rigged up Go-International Jet, perforated four 3/8" holes at 8056' using 1-11/16" bore tubing perforator. Set fullbore at 7864'. Could not break down formation with 3100 psi surface pressure.

NOTE: All measurements are to center of packing element. Add 5' to all figures for correlation with CBL/CCL.

3-22 With fullbore hanging at 8093' pumped in 500 gallons of 15% HCL. Pulled up and set fullbore at 7555'. Pressure tubing to 3000 psi and shut well in for 2-1/2 hours. Broke down holes at 8056' with 4000 psi. Took fluid at a rate of 8 cf/minute at 3500 psi. Hung fullbore at 8093' and backscuttled out acid. Pulled up and hung fullbore at 7864'. With 20 cf fresh water ahead, mixed and pumped 50 sacks Class "G" cement with 0.75% CFR-2. Displaced with 5 cf fresh water and 161 cf workover fluid. Closed tool and squeezed 49 cf cement to formation. Final pressure 3300 psi. Released pressure and had 2 cf bleed-back. Used Halliburton equipment. Pulled fullbore packer. Started in hole with 4-1/8" bit and 5" casing scraper.

PORTER 47

DAILY DRILLING REPORT

3-13-73 Filled hole. Took one barrel. Circulated out fill from 8345' to 8357'. Turn on junk at 8357'. Circulated on bottom for 1-1/2 hours. Started out of hole. Rig broke down with bit and scraper at 7633'. Circulated 2 hours from 7633' waiting on engine.

3-14 Replaced rig engine.

3-15 Filled hole; took one barrel. Circulated one hour from 7633'. Pulled bit and scraper. Rigged up Dresser-Atlas. Ran cement bond log 6700-8354', Neutron Lifetime gama ray log 7780-8352' and Densi-Log 7800-8351'. Start in hole with 7" casing scraper.

3-16 Filled hole. Took one barrel. Continued running 7" casing scraper. Tagged top of liner at 6887'. Started out of hole. Discovered cracked brake flange on rig. Shut down for repairs with scraper at 1532'.

3-17 Pulled 7" scraper from 1532'. Made one 5" Baker Model "C" bridge plug at 1233'. 2-3/8" tubing below 7" Baker fullbore packer. Ran in and set in bridge plug at 8122' with fullbore hanging 6833', tail to 8075'. Tested from surface to 2811' with 1500 psi. No good. Set full bore at 6833' to 8122' with 1500 psi. No good. Tested on surface to 6833' with 1700 psi for 15 minutes. OK. Dropped down to retrieve bridge plug. Discovered that bridge plug as not set properly. Reset same at 8122'. Reset fullbore at 6833', tail to 8075'. Tested 6833' to 8122' with 1700 psi. No good. Retrieved bridge plug and set same at 6911'. Set fullbore at 5609', tail to 6851' and tested 5609-6911' with 1700 psi for 15 minutes, OK. Splice OK. Pulled bore and set same at 3525', tail to 4767'. Tested from surface to 3525' with 2150 psi for 15 minutes, OK. Pulled fullbore and set same at 2505' tail to 3747'. Tested from surface to 2505' with 3200 psi for 15 minutes, OK. Pulled full bore packer. Test summary 7" casing, OK. mix 7", splice OK. Located leak in 5" liner between 6911-8122'.

3-19 Filled 7"x 13-3/8" annulus. Took 45 barrels. Tore out BOPE and tubing heads. Rigged up spear in casing jacks. Could not unland 7" casing. Cut off casing head. Found 184,000# on casing. Welded extension on 7" casing.

3-20 X-rayed 7" weld, OK. Cut off base plug and welded on new casing head. X-rayed casing head weld, OK. Relanded 7" casing with 185,000#. Installed new tubing head. Tested primary fill with 3275 psi for 15 minutes, OK. Tested secondary fill with 3300 psi for 15 minutes, OK.

Ex. I - 20

Due to the large file size, this exhibit is an excerpt. The native file of this document is available upon request.

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION

DIVISION OF OIL AND GAS
RECEIVED
APR 14 1977
SANTA PAULA, CALIFORNIA

DIVISION OF OIL AND GAS

Notice of Intention to Rework Well

This notice and indemnity or cash bond shall be filed, and approval given, before rework begins. If operations have not commenced within one year of receipt of the notice, this notice will be considered cancelled.

FOR DIVISION USE ONLY		
BOND	OGD114	OGD121
7373	✓	✓

DIVISION OF OIL AND GAS

In compliance with Section 3203, Division 3. Public Resources Code, notice is hereby given that it is our intention to rework well No. PORTER (#25, API No. -,

Sec. 28, T. 3N, R. 16W, S.B. B. & M., Aliso Canyon Field, Los Angeles County.

The present condition of the well is as follows:

1. Total depth. 8625'

2. Complete casing record, including plugs and perforations:

13 3/8" cemented 808'

7" cemented 5770', WNSO 5755', squeezed - WSO 5751'

5" cemented 8600', WSO 8211'
Perforated 8218'-8494'

3. Present producing zone name SESNON Zone in which well is to be recompleted -

4. Present zone pressure 2500 psi New zone pressure -

5. Last produced Gas Storage Well
(Date) (Oil, B/D) (Water, B/D) (Gas, Mcf/D)

or

6. Last injected
(Date) (Water, B/D) (Gas, Mcf) (Surface pressure, psig.)

The proposed work is as follows:

1. Move in, kill well and install B.O.P.E.
2. Recover Otis hydraulic packers.
3. Pressure test casing and perfrom remedial work, as indicated.
4. Set Baker Retrieva-"D" packer at 7850'.
5. Run tubing and safety system. Return to Gas Storage.

It is understood that if changes in this plan become necessary we are to notify you immediately.

Address P.O. Box 3249, Terminal Annex
(Street)
Los Angeles, California 90051
(City) (State) (Zip)
Telephone Number (213) 689-3561

SOUTHERN CALIFORNIA GAS COMPANY
(Name of Operator)
By P.S. Magruder Jr. by Guy C. Anderson
(Name) P.S. Magruder, Jr. (Date)
Type of Organization Corporation
(Corporation, Partnership, Individual, etc.)

OG107 (8-75—GSRI—15M)

FORM 103

SUBMIT IN DUPLICATE

△ OSP

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION

DIVISION OF OIL AND GAS

History of Oil or Gas Well

OPERATOR Pacific Lighting Service Company FIELD Aliso Canyon

"SFZ U" P-25
Well No. Porter 25, Sec. 28, T. 3N, R. 16W, S.B. B. & M.

Date October 24, 1973 Signed R. B. Magruder Jr.

P. O. Box 54790, Terminal Annex
Los Angeles, California 90054 (213) 689-3561 Title
(Address) (Telephone Number) (President, Secretary or Agent)

It is of the greatest importance to have a complete history of the well. Use this form to report a full account of all important operations during the drilling and testing of the well or during re-drilling, altering of casing, plugging, or abandonment with the dates thereof. Be sure to include such items as hole size, formation test details, amounts of cement used, top and bottom of plugs, perforation details, sidetracked junk, bailing tests, shooting and initial production data.

Date	
1973	
1-19	Moved in C.P.S. production rig. Sucker rods had been pulled but rod pump was stuck and remained in well. Blew down gas pressure on tubing and casing, unlanded tubing and opened Page tubing drain. Re-landed tubing and filled casing with 110 bbls. brine-polymer work over fluid and attempted to backscuttle through pump and drain at 1500 psi without success. Attempted to circulate through tubing at 1350 psi without success. Installed class III B.O.P.E.
1-20	Tested B.O.P.E. to 2000 psi. Shot one 3/8" hole in tubing at 8380'. Circulated through tubing, separating kill fluid and oil returning through casing, losing approximately 100 bbls. to formation, in skimmings from circulating tank and mixed with oil to flow line. Pulled tubing. Coming out, Page double tubing anchor stuck at 6042' but worked free in one hour. Lost in hole one 5" x 1-3/4" slip segment and button from Page 5" tubing anchor.
1-21	Idle
1-22	Filled hole, took 9 bbls. Ran 7" scraper and 6-1/8" bit to top of 5" liner at 5678'. Ran 5" scraper and 4-1/8" bit which stopped at tight place at 6042'. Ran 4-1/8" swage and worked through partially collapsed 5" casing at 6042' to 6043'.
1-23	Continued working 4-1/8" swage through tight pipe at 6042' until swage worked through freely. Pulled out but lost swage tool in hole. Ran in, found swage tool at 7618'.
1-24	Recovered 4-1/8" swage. Ran 4-1/8" bit and 5" scraper drifted at 4-1/8" and worked through tight spot at 7618' but stopped and could not be worked through tight spot at 8455'
1-25	Ran 3-7/8" bit and 5" scraper set at 3-7/8" O.D. which could not be worked below 8455'. Ran Dresser-Atlas Neutron Lifetime, Density and Cement bond logs.
1-26	Attempted to run 5" Baker Lok-Set bridge plug but plug would not go through tight pipe at 6042'. Ran 4-1/8" swage and worked through tight places at 6042' & 7618'.

1973

1-27 Checked tight 5" casing at 7618' and 6042' with 4-1/8" swage OK after setting overnight. Ran 126' of 2-3/8" O.D. plain end flush joint tubing stinger, went through tight 5" casing at 8455' and backscuttled out sand fill from 8513' to 8550'.

1-28 Idle.

1-29 Set 5" bridge plug at 8160' to plug well to change wellhead. Tested plug and casing with rig pump to 1500 psi but pressure bled off to 1150 psi in 5 minutes. Set plug at 7575' and tested but bled off from 1600 psi to 1250 psi in 75 minutes. Set plug at 6010' and tested at 1825 psi OK. Above tests indicate leaks in 5" casing between 6010' and 8160'. Pulled and re-dressed bridge plug. Reran 5" bridge plug with squeeze packer and pressure tested tubing at 5000 psi to 8160'.

1-30 Set bridge plug at 8160' and packer at 8120' and tested between at 3000 psi OK using B-J pump truck. Set packer at 7663' and tested 5" casing from 7663' to 8160' at 3000 psi OK. Set packer at 7600' and tested 7600' to 8160' and pumped away 5 cu. ft. per minute at 2000 psi. Tested 7" casing and 5" casing from surface to 7600' at 2000 psi which leaked 200 psi in 7 minutes. The tests indicated hole in 5" at 7618', the depth at which the 5" was partially collapsed and a smaller leak between 7600' and surface. Set squeeze packer at 7427' to cement hole at 7618'. Pumped in 20 cu. ft. water, 40 sacks Class "G" cement with 0.2% B-J, Inc. D-19 fluid loss additive and 0.2% D-31 dispersant and 4 cu. ft. water and squeezed out 36 cu. ft. cement through holes at 7618' in stages to a final pressure of 2450 psi. Cement in place 2:40 PM. Calculated top of cement 7518'. Held pressure on cement until 5:00 PM. Set packer at 6060' and tested 5" to calculate top of cement at 7518' at 2200 psi which leaked off 300 psi in 7 minutes. Tested 5" and 7" casing from 6060' to surface which held 2000 psi for 4 minutes, increased pressure to 2200 psi which held 3 minutes then broke down and leaked off 100 psi in 40 minutes. Set packer at 6806', 6494', 6682', 6620', 6557' and 6588' and tested from packer to calculate top of cement at 7518' and determined existence of small leaks in the 5" casing at or near a collar at 6588' and between 6806' and calculated top of cement at 7518'.

1-31 Pulled squeeze packer to 6342' and ran Dresser-Atlas through tubing perforator and shot four 3/8" jet holes at 6593'. Set packer at 6342' and broke down holes at 6593' with 7 cu. ft. per minute at 2000 psi. Pumped in 20 cu. ft. water, 60 sacks class G cement with 0.2% D-19 and 0.2% D-31 and 4 cu. ft. water and squeezed out 60 cu. ft. cement through holes at 6593' at a final pumping pressure of 2200 psi, but leaked off to 1800 psi in 40 minutes. Cement in place 9:40 AM. Calculate top of cement 6513'. Released pressure at 12:00 Noon. Retested 6342' to calculate top of cement at 6513' at 2200 psi which leaked off 100 psi in 10 minutes, indicating an additional leak between 6342' and calculate top of cement at 6513'. Pulled squeeze packer and ran in with 4-1/8" bit and 5" scraper drifted to 4-1/8". Drilled out cement stringers from 6475' to 6489', leaving cement plug from 6489' to squeezed holes at 6593'.

2-1 Pulled bit and scraper. Ran 5" squeeze packer and set successively at 6434', 6310', 6376', 6366', 6355' and at 6310' and 6376' again and tested from packer to top of cement plug at 6489' proving existence of leaks in the 5" casing from above 6310' to 6434'. Pulled packer. Ran 4-1/8" bit and scraper and drilled out cement from 6489' to 6551'.

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2-2 Continued drilling out cement from 6551' to 6599'. Ran on in with 4-1/8" bit and scraper, hit cement stringers at 7470', firm cement from 7590' to 7624'. Ran on in and circulated hole clean from top of sand plug at 8144'.

2-3 Ran Dia-log Caliper survey in 5" casing from 8141' to 5678', indicating no appreciable loss of inside wall metal.

2-4 Idle.

2-5 Made four attempts to run Schlumberger electronic casing inspection log on 5" casing without success. Tool malfunctioned.

2-6 Ran Schlumberger electronic casing inspection log in 5" casing from 7730' to shoe of 7" casing at 5770', indicating more than 90% wall thickness remaining throughout. The log indicated 5" joints to be flush joint, such as Hydril "EU".

2-7 Ran and set 5" bridge plug at 7668' and 5" packer at 7602' and tested 7602' to 7668', including cemented holes at 7618', to 2100 psi for 35 minutes OK. Moved bridge plug to 7602' and set packer at 6806' and tested 6806' to 7602' at 1700 psi which leaked off 100 psi in 50 minutes confirming existence of small hole in 5" casing between 6806' and 7602'. Set packer at 6438' and tested 6438' to 7602', including cemented holes at 6593', to 1700 psi which leaked off at rate of 1-1/2 psi per minute, indicating cemented holes were holding OK and that leak off was at the small hole between 6806' and 7602'. Pulled bridge plug to 6475' and set packer as outlined below to re-confirm leaks in the 5" casing between 6342' and 6513' as reported on 1/31/73 and leaks in the area of 6310' to 6434' as reported on 2/1/73. Set packer and tested 5" casing (1) 6376' to 6475' at 2200 psi for 15 minutes OK; (2) tested 6314' to 6475' at 2000 psi which leaked off to 1900 psi in 5 minutes; (3) tested 6345' to 6475' at 2000 psi which leaked off 40 psi per minute. Also when packer was set at 6314', tested 5" and 7" casing from 6314' to surface at 1500 psi for 25 minutes OK. The above tests showed the tests conducted on 2/1/73, which indicated leaks "from above 6310' to 6434'", to be in error due to a fault in the packer unknown at that time and that the only leak in the 5" between 6342' and 6513' is between 6345' and 6376', probably at a joint at 6363'.

2-8 Moved bridge plug to 7603' to pinpoint leak in 5" casing between 6806' and 7602' as previously determined. Set packer at 7309', 7063', 6938', 6876' and 6907' and tested to 7603' at 2100 psi which showed hole to be in 5" casing between 6907' and 6938', probably at joint at 6923', which leaked off at 10 psi per minute. Pulled packer to 6691'. Ran Dresser-Atlas through tubing gun and shot four 3/8" holes at 6927' to 6928'. Set packer at 6691'. Holes at 6927' to 6928' would not take fluid at 2600 psi, only leaking off from 2600 psi to 1700 psi in 5 minutes. Spotted 200 gallons 15% inhibited HCL in 5" casing from 6968' to 6708'.

2-9 Set packer at 6691' and broke down holes at 6927' with 5 cu. ft. per minute at 2500 psi. Backscuttled from 6998' to circulate out HCL acid. Re-set packer at 6691' and cemented holes at 6927' as follows: Pumped in 20 cu. ft. water, 40 sacks Class "G" cement, 4 cu. ft. water and displaced with 252 cu. ft. mud staging 36 cu. ft. cement out holes at 6927' at a final pump pressure of 2000 psi. Cement in place 9:10 AM. Calculate top of cement at 6827'. Held 2000 psi 30 minutes then tested against cement at 2200 psi OK. Pulled packer. Ran 3-1/2" gun

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2-9 (cont'd) and shot four 0.38" holes at 6368'. Set packer at 6130' and broke down holes at 6368' with 6 cu. ft. per minute at 1700 psi. Cemented holes at 6368 as follows: pumped in, through 3248' 2-3/8" tubing and 2882' 3-1/2" tubing, 20 cu. ft. water 70 sacks Class "G" cement with 0.20% D-19 and 0.20% D-31, 4 cu. ft. water and displaced with 225 cu. ft. mud squeezing out 70 cu. ft. cement through holes at 6368' at a final pump pressure of 1900 psi and a final static pressure of 1600 psi. Calculated top of cement 6268'. Cement in place 4:50 PM. Released pressure at 6:30 PM. Pulled packer.

2-10 Removed B.O.P.E. and tubing head in order to remove existing casing head and weld on new casing head, but shut down at 11:00 AM. Unable to make weld in rain.

2-11 Idle.

2-12 Unlanded 7" casing with 160,000 pounds. Removed existing casing head and welded on new 5000 psi API 13-3/8" casing head by making butt weld in 13-3/8" casing 3" above cellar floor. X-rayed weld OK.

2-13 Relanded original 7" casing with 160,000 pounds. Installed 5000 psi API seal flange and tubing head and tested seals to 3400 psi OK. Ran 4-1/8" bit and scraper, hit cement stringers at 6193', firm cement at 6258' and drilled out cement to 6334'.

2-14 Continued drilling out cement 6334' to 6375', 7' below holes at 6368'. Pressure tested holes at 6368' with rig pump at 1500 psi which bled off to 1210 psi in 50 minutes. Ran on in with 4-1/8" bit and scraper and hit cement at 6720' and drilled out cement to holes at 6927'. Pressure tested complete interval from top of sand at 7583' to surface including the two sets of squeezed holes at 6368' and 6927' at 1500 psi with rig pump which bled off to 1170 psi in 28 minutes. Ran in, tagged top of sand at 7583' and pulled bit.

2-15 Ran 5" packer to test cement jobs at 6927', 6593' and 6363'. Set packer at 5704' and tested 5704' to surface at 1590 psi 20 minutes OK. Set packer at 6425' and tested 6425' to surface at 1520 psi which leaked off to 1250 psi in 5 minutes, indicating holes at 6368' were leaking. Set packer at 6441' and tested 6441' to sand at 7583' at 1500 psi which leaked off to 1395' in 30 minutes, which indicated holes at 6927' and/or 6593' were leaking. Set packer at 6900' and tested holes at 6927' which leaked off from 1975 psi to 1875 psi in 25 minutes. Using Dresser-Atlas 1-11/16" through tubing perforator and Di-Kone link jet, shot 2 holes at 6930'. Set packer at 6683' and broke down holes at 6930' with 3 cu. ft. per minute at 3200 psi. Squeezed holes at 6930' with 25 sacks Class "G" cement at pumping pressure of 3000 psi, which bled off to 1800 psi in 5 minutes, except final stage built up to and held 2000 psi. Calculated top of cement at 6770'.

2-16 Pulled packer from 6683' to 6430' and found tubing plugged. Pulled out and found cement in bottom 90' of 2-3/8" tubing. Ran 7" packer to test 7" casing. The 7" packer (6.200" O.D.) stopped going at 5093', 585' above top of 5" liner. Set packer at 5063' and tested 7" casing to surface at 2200 psi 20 minutes OK. Set packer at 3000' and tested 7" casing to surface at 2550 psi for 20 minutes OK.

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2-16 (cont'd) Set packer at 2002' and tested 7" casing to surface at 3100 psi for 20 minutes OK. Ran 5" packer and tubing plug catcher and checked displacement of 3248' of 2-3/8" tubing and 3435' of 3-1/2" tubing finding displacement to be 16 cu. ft. more than standard due to rod wear. Set packer at 6437' and tested cemented holes at 6593' which leaked off from 1700 psi to 1630 psi in 20 minutes.

2-17 Pulled tubing. Using Dresser-Atlas 3-1/2" Gun and Golden Jets, shot two 1/2" holes at 6595'. Set packer at 6463' and broke down formation at 14 cu. ft. per minute at 3200 psi. Squeezed holes with 100 sacks Class "G" (114 cu.ft. cement), staging to a final pressure of 3000 psi, putting 101 cu. ft. out holes. Calculated top of cement 6523'. Set packer at 6122' and broke down holes at 6368' with 8 cu. ft. per minute at 3200 psi. Squeezed holes at 6368' with 70 sacks Class "G" (80 cu.ft. cement), staging to a final pressure of 3500 psi, putting 60 cu. ft. cement out holes. Calculated top of cement 6168'. Pulled packer and ran 4-1/8" bit to 3300'.

2-18 Idle.

2-19 Ran on in with 4-1/8" bit and 4-1/8" scraper, found top soft cement at 6196' and drilled out cement to 6326'. No cement between 6326' and supposed leak at 6368'. Evidently original squeeze on holes at 6368' on 2-9-73 was OK but break down on 2-17-73 with packer at 6122' was out new holes 6326'. Ran on in and hung bit at 6551' and tested 7" and 5" casing from surface to below 6551' with rig pump at 1520 psi for 20 minutes, OK. Rotated bit and scraper finding cement stringers from 6496' to 6582' and solid cement from 6582' to 6601'. This cement was left in place when squeezing holes at 6595' on 2-17-73. Ran on in and hit top of cement at 6684' from squeeze on holes at 6930' on 2-15-73. Hung bit at 6684' and pressure tested from 6684' to surface at 1360 psi for 20 minutes OK. Drilled out hard cement from 6684' to 6801'.

2-20 Continued drilling out cement 6801' to 6931'. Ran on in to 6962' and pressure tested holes at 6930' from surface at 1300 psi which bled off to 930 psi in 20 minutes. Retrieved bridge plug from 7602'.

2-21 Using Dresser-Atlas 3-1/2" hollow carrier and NCF III 11 gram Golden Jet, shot 4 0.31" holes per foot from 8088'-8086', 8080'-8074', 8070'-8056', 8026'-8001', and 7998'-7982'. Ran Johnston formation test tool on 3248' 2-3/8" and 4619' 3-1/2" tubing. Set packer at 7894' (27' of tools above packer) with tail to 7912', with 1/2" flow bean in tester. Flowed well for clean up period from 2:45 PM to 6:10 PM then shut in at tester. Final rate 2.8 MMCF/day approximately at 578 psi surface flowing pressure on 48/64" surface bean. Produced 3.3 bbls. oil last hour.

2-22 Flow tested S-8 zone from 6 AM to 6 PM with perforations open and test tool set as outlined on 2-21-73. Final flow rate 3252 MCF/day on 3/4" surface bean and 604 psig surface flowing pressure. Produced 9.0 bbls. oil and 15.4 bbls. water in the 12 hour test.

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2-23 Pulled test tools. Using Dresser-Atlas 3-1/2" hollow carrier and NCF III 11 gram Golden Jets, perforated four 0.31" holes per foot at 7888'-7894', 7914'-7926' and 7950'-7956'. Ran Johnston tester and bridge plug. Set plug at 7970' and test packer at 7821' with tail to 7846'. Opened tester from 4:18 PM to 6:00 PM for clean up flow period. At 6:00 PM flowing through 1" bean at surface rate was approximately 2300 MCF/day at 635 psi surface pressure.

2-24 Flow tested S-4 zone from 6:05 AM to 6:05 PM with tester set as outlined on 2-23-73. Flow rate at 6:05 PM 2897 MCF/day at 511 psi surface pressure. Fluid produced for the 12 hours was 21.3 bbls. gross, 10.4 bbls. net.

2-25 Idle.

2-26 Pulled tester tool. Moved bridge plug from 7970' to 7872'. Shot four 0.31" holes at 7853'. Ran Johnston tester on 3248' 2-3/8" and 4569' 3-1/2" dry tubing. Set packer at 7817' with tail to 7833'. Tester open at 5:25 PM for one hour for WSO test on holes at 7853'. Had weak diminishing blow for 40 minutes, dead last 20 minutes. Had 10' rise drilling fluid. Charts OK. I.H.P. 3460 psi, I.F.P. 30 psi, F.F.P. 0 psi, F.H.P. 3456 psi witnessed and approved by Peter Wygle of Division of Oil & Gas.

2-27 Ran squeeze packer and moved bridge plug from 7872' to 7061'. Set packer at 6688' and tested cemented holes at 6930' at 2500 psi for 20 minutes, OK. Tested from 6688' to surface at 1300 psi which bled off to 1075 psi in 15 minutes. This test indicated that holes at 6595' or 6368' had broken down since good tests were made on 2-19-73 and that holes at 6930' were OK. (Tests conducted on 2-20-73 indicated holes at 6930' were bad). Set packer at 6564' and tested 6564' to 7061' at 1300 psi 10 minutes OK, showing holes at 6593' were OK. Set packer at 6315' and tested 6315' to 7061' at 1300 psi which leaked to 900 psi in 5 minutes, indicating holes at 6368' and/or 6326' were bad. Tested from 6315' to surface at 1300 psi 20 minutes OK. Packer failed. Pulled packer and retrieved plug from 7061'.

2-28 Ran squeeze packer and bridge plug. Set bridge plug at 6579' and packer at 6564' and tested between at 2500 psi 5 minutes OK. Set packer at 6346' and tested to 6579' at 1300 psi which bled off to 800 psi in 4 minutes, indicating holes at 6368' were leaking. Tested from 6346' to surface at 1300 psi 10 minutes OK. Broke down holes at 6368' with 8 cu. ft. per minute at 2500 psi. Cemented holes at 6368' with 57 cu. ft. Class "G" cement to a final pressure of 3000 psi. Cement in place 2:06 PM. Held 3000 psi 5 minutes, released squeeze tool and backscuttled 37 cu. ft. cement. Calculate 18 cu. ft. out holes at 6368', 2 cu. ft. in 5" casing. Pulled packer.

3-1 Ran 4-1/8" bit and scraper. Drilled out firm cement from 6346' to 6371'. Pressure tested casing from 6579' to surface at 1000 psi 20 minutes OK. Pulled bit.

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3-2 Retrieved bridge plugs from 6579' and 8160'. Hole took 120 bbls. after pulling bridge plug at 8160'. Ran Baker Model D production packer on Dresser-Atlas wireline. Could not get below tight spot in 5" liner at 7618'. Pulled out.

3-3 Ran 4-1/8" tapered mill. Milled tight spots in 5" liner at 6047' and 7618'. Mixed 460 bbls. mud. Checked liner to 8163' with mill.

3-4 Idle.

3-5 Ran Johnston squeeze packer and bridge plug in tandem to test milled spots. Set bridge plug at 7720'. Set packer at 7710' and tested bridge plug with 1075 psi for 15 minutes OK. Pulled up and set packer at 7578'. Tested 7578'-7710' with 1035 psi for 25 minutes OK. Retrieved bridge plug and reset same at 6167'. Set packer at 6151' and tested bridge plug with 1350 psi for 15 minutes OK. Pulled up and set packer at 6023'. Tested 6023' to 6167' with 1150 psi for 25 minutes OK. Ran Baker Model "D" on Dresser Atlas wireline. Could not get below tight spot at 7618'. Maximum O.D. Baker packer 3.968", maximum O.D. Johnston packer 3.968", maximum O.D. tapered mill 4.125". Suspect dogleg at 7618'.

3-6 Made up Baker Model "D" on tubing. Measured in and set Model "D" at 8100'. No trouble getting past 7618'. Made up completion string (see tubing detail). Tested 6060' of 1/4" control line and 2-3/8" Page safety valve with 5000+ psi for 15 minutes OK. Started Hydrotesting in hole with tubing.

3-7 Continued in hole with tubing. Made splice at end of spool and tested same with 5000+ psi for 15 minutes OK. Spaced out to land tubing. Tested control line and safety valve through donut with 5000+ psi for 30 minutes OK. Landed tubing with 13,000 lbs. on Model "D" packer. Tore out B.O.P.E. Installed production head. Tested control system and safety valve through head with 5000+ psi for 30 minutes OK. Tested production head through test port with 4575 psi for 15 minutes OK. Tested production head through unibolt with 4500 psi for 15 minutes OK. Rigged up Otis wireline and closed all three sleeves (7792', 7958', 8090'). Set No Go plug in Otis X nipple at 8099'. Pressured tubing to 2300 psi and held for 5 minutes to set 2 Otis Model RH hydraulic packers (packers at 7833' and 7963'). Tested setting of top packer by pressuring up on annulus. Held 750 psi for 10 minutes OK.

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TUBING DETAIL

No.Jts.	Item	Length	Depth
	Below K.B.	6.92	
	Donut & 2-7/8" x 3-1/2" EU 8 Thd X-Over	1.00	
	3-1/2" EU 8 Thd pup jt.	2.15	
	3-1/2" EU 8 Thd pup jt.	4.20	
	3-1/2" EU 8 Thd pup jt.	10.00	
	3-1/2" EU 8 Thd pup jt.	10.00	
178	3-1/2" EU 8 Thd J-55 tubing	5538.94	5573.21
	3-1/2" x 2-7/8" EU 8 Thd crossover	1.10	5574.31
1	2-7/8" EU 8 Thd J-55 tubing	31.62	5605.93
	2-7/8" EU 8 Thd Otis X nipple 2-5/16 I.D.	1.00	5606.93
1	2-7/8" EU 8 Thd J-55 tubing	30.35	5637.28
	2-7/8" x 2-3/8" EU 8 Thd crossover	1.10	5638.38
69	2-3/8" EU 8 Thd J-55 tubing	2154.35	7792.73
	2-3/8" EU 8 Thd Otis Sliding Sleeve (closed)	2.80	7795.53
1	2-3/8" EU 8 Thd J-55 tubing	31.12	7826.65
	2-3/8" EU 8 Thd Page Safety Valve (will not close)	3.10	7829.75
	2-3/8" x 5" 18# Otis Hydrostatic set packer w/15,000# shear out	4.05	7833.80
4	2-3/8" EU 8 Thd J-55 tubing	124.40	7958.20
	2-3/8" EU 8 Thd Otis Sliding Sleeve (open)	2.80	7961.00
	2-3/8" EU 8 Thd N-80 tubing pup jt.	2.25	7963.25
	2-3/8" x 5" 18# Otis Hydrostatic set packer w/15,000# shear out	4.05	7967.30
4	2-3/8" EU 8 Thd J-55 tubing	123.07	8090.37
	2-3/8" EU 8 Thd Otis Sliding Sleeve (closed)	2.80	8093.17
	2-3/8" EU 8 Thd N-80 tubing pup jt.	6.00	8099.17
	2-3/8" Otis X nipple 1.875 I.D. & 1.791 No. Go. (plug in place)	1.10	8100.27
	2-3/8" EU 8 Thd Baker Locator Sub. Landed in Model D pkr. @ 8100' w/13,000#	.45	8100.72
	5 sets Baker Seals	4.50	

3-8 Opened sliding sleeves at 7792' and 7958' with Otis wireline unit. Closed safety valve. Unloaded 240 bbls. workover fluid with nitrogen. Closed sleeve at 7792'. Blew down tubing until fluid hit and well came in. Shut well in. Tubing pressure built up to 1176 psi. 2200 psi nitrogen pressure on annulus. Defective safety valve indicated. Made flow line connection. Pressured up on control line. Flowed well. Bled off control line and attempted to bleed off tubing above safety valve. No good. Well continued to flow. Repeated procedure. No good.

3-9 Cycled valve two more times as above with no results 2200 psi still on annulus. Top of Otis packer, sliding sleeve, and squeeze jobs above Otis packer all good. Malfunction definitely in safety valve. Pressured control line and closed sleeve at 7958' with Archer Reed wireline. Bled off control line and checked safety valve with 1-3/4" impression block. Valve wide open. Pressured up tubing to

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3-9 (cont'd) 3000 psi with nitrogen in attempt to hydraulic the valve closed. Impression block again showed valve to be wide open. Pressured control line to 4500 psi and opened sleeves at 7792' and 7958'. Closed sleeve at 7792'. Do not believe valve to be locked open as sleeve shifting tool did not see safety valve. Possible that valve equalizing bypass is clogged with well trash and that prolonged flow periods will clean up valve and thus allow it to operate properly. Tore out C.P.S. and moved out.

Final status of downhole equipment:

2-7/8" x 2-5/16" I.D. Otis "X" nipple to seat Udall valve @ 5606'
2-3/8" Otis sliding sleeve (circulating) closed @ 7792'
2-3/8" Page Safety Valve open @ 7827'
2-3/8" Otis sliding sleeve (S-4 production) open @ 7958'
2-3/8" Otis sliding sleeve (S-8 production) closed @ 8090'
2-3/8" x 1.875" I.D. Otis X nipple with No Go plug in place @ 8099'

Approximately 140' workover fluid (1.7 bbl.) left in annulus.

FORM 109

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION

DIVISION OF OIL AND GAS

Report on Operations

No. T 273-158

Mr. P. S. Magruder, Jr., Agent
Pacific Lighting Service Company
P O Box 54790, Terminal Annex
Los Angeles, California 90054

Santa Paula Calif.
March 20, 1973

DEAR SIR:

Operations at well No. "SFZU" P-25, API No. (037) 00712, Sec. 28, T. 3N, R. 16W, S.B., B & M. Aliso Canyon Field, in Los Angeles County, were witnessed on Feb. 26, 1973. Mr. P R Wygle, engineer, representative of the supervisor was present from 1900 to 2100. There were also present J. Melton, foreman

Present condition of well: 13 3/8" cem. 808'; 7" cem. 5770', c.p. 5755', perf. 5751' WSO; 5" cem. 5678-8600', perf. 7853' WSO, perf. 8211' WSO, perf (ints) 8225-8494'. T.D. 8625'. Plugged with cem. 8600-8560'.

The operations were performed for the purpose of testing the 5" shut-off by means of a formation tester.

DECISION:

THE 5" SHUT-OFF AT 7853' IS APPROVED.

a
cc: Operator

JOHN F. MATTHEWS, JR.
State Oil and Gas Supervisor

By L E Rutins Deputy

FORM 111

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION

DIVISION OF OIL AND GAS

REPORT ON PROPOSED OPERATIONS No. P 273-44

GAS STORAGE

Mr. P. S. Magruder, Jr., Agent
Pacific Lighting Service Company
P O Box 54790, Terminal Annex
Los Angeles, California 90054

Santa Paula Calif.
January 29, 1973

DEAR SIR:

Your proposal to convert to gas storage Well No. "SFZU" P-25 (037-00712), Section 28, T.3N, R.16W, S.B B. & M., Aliso Canyon Field, Los Angeles County, dated 1/15/73, received 1/26/73, has been examined in conjunction with records filed in this office.

THE PROPOSAL IS APPROVED PROVIDED THAT:

1. Blowout prevention equipment, at least of the Division of Oil and Gas Class III rating, shall be installed and maintained in operating condition at all times.
2. Drilling fluid of proper weight and consistency shall be used to keep the well under control at all times; and a reserve supply of this material shall be kept on hand to meet any emergency. NO CONTAMINATES OR TOXIC MATERIAL SHALL BE USED IN ANY DRILLING FLUID THAT IS TO BE PLACED IN AN UNLINED SUMP.
3. THIS DIVISION SHALL BE NOTIFIED TO WITNESS the test of the 5" water shut-off at 7850'.

Blanket Bond
ALL:a
cc: Operator

JOHN F. MATTHEWS, JR., State Oil and Gas Supervisor

By [signature], Deputy

87628-708 11-71 35M ③ OSP

FORM 107

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION

DIVISION OF OIL AND GAS

RECEIVED

Notice of Intention to Deepen, Redrill, Plug or Alter Casing in Well

This notice must be given before work begins; one copy only

Los Angeles, Calif. January 15 1973

DIVISION OF OIL AND GAS

In compliance with Section 3203, Chapter 93, Statutes of 1939, notice is hereby given that it is our intention to commence the work of deepening, redrilling, plugging or altering casing at Well No. "SFZU" P-25
(Cross out unnecessary words)
, Sec. 28, T. 3N, R. 16W, SB B. & M.

Aliso Canyon Field, Los Angeles County.

The present condition of the well is as follows:

1. Total depth. 8625', Plug 8560'.

2. Complete casing record, including plugs:

13-3/8" cemented 808'
7" cemented 5770'
4 holes 5755' cemented
4 holes 5751' WSOK
5" liner 5678' to 8600', ineffective below 8560'
5" x 7" Lap WSOK
8211' 4 holes WSOK
Jet perforations 2 holes per/foot and bullet perforations 2 holes per foot 8225'-8281', 8309'-8327', 8335-8356', 8367'-8385', 8387'-8397', 8416'-8446' and 8452'-8494'. Re-perforated 2 jet holes per foot 8218'-8274', 8280'-8321', 8331'-8352', 8363'-8371', 8383'-8393' and 8412'-8442'.

3. Last produced. _____ (Date) _____ (Oil, B/D) _____ (Water, B/D) _____ (Gas, Mcf/D)

The proposed work is as follows:

1. Demonstrate WSO at 7850'.

2. Perforate and/or re-perforate in the Sesnon and Frew zones between 7876' and 8560' as required to convert well to a gas storage well.

MAP | MAP | COPY | MAIL | FORMS 121

P. O. Box 54790, Terminal Annex
Los Angeles, Ca. 90054
(Address)

(213) 689-3561
(Telephone No.)

Pacific Lighting Service Company
(Name of Operator)

By R. B. Magruder Jr.

48086-708 11-70 15M OSP

FORM 156

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION
DIVISION OF OIL AND GAS

REPORT OF PROPERTY AND WELL TRANSFER

Field or County: Los Angeles — District: 1

Former Owner: Getty Oil Company — Date: Sept. 26, 1968

Description of Property: Sec. 27,28,34, T. 3 N., R. 16 W., S. B. B. & M.

Sec. 27:
*"Fernando Fee" 32 (037-00686)
"Porter" 12 (037-00701)
" 30 (037-00717)
" 31 (037-00718)
" 32 (037-00719)

List of Wells
"Porter" 36 (037-00723)
" 37 (037-00724)
" 45 (037-00732)

Sec. 28:
"Porter" 4 (037-00699)
" 25 (037-00712)
" 26 (037-00713)
" 34 (037-00721)
" 35 (037-00722)
" 38 (037-00725)
" 39 (037-00726)

Sec. 28:
"Porter" 40 (037-00727)
" 41 (037-00728)
" 42 (037-00729)
" 43 (037-00730)
" 44 (037-00731)
" 46 (037-00733)
" 47 (037-00734)
"Porter-Sesnon" 42 (037-00753)

Sec. 34:
"Fernando Fee" 31 (037-00685)
" 33 (037-00687)
" 34 (037-00688)
" 35 (037-00689)
"Mission-Adrian Fee" 3 (037-00693)
" 4 (037-00694)
" 5 (037-00695)

Date of Transfer: August 1, 1968
New Owner: GETTY OIL COMPANY, OPERATOR
Address: 3450 Wilshire Boulevard, Room 720
Los Angeles, California 90005
Telephone No. 381-7151

Type of Organization: Corporation
Reported by: C. G. Nelson for Getty Oil Co. & Getty Oil Co., Operator (letter of 8-7-68) *
Confirmed by:
New Operator New Status: PA , Old Operator New Status: PA
Request Designation of Agent: No

Remarks:

ag
cc: F. E. Kasline
Production Dept.
Conservation Committee

Wm. C. Bailey
Deputy Supervisor

	INITIALS	DATE
Form 121		
New Well Cards		
Well Records		
Electric Logs		
Production Reports		
Map and Book		
Form 148		
Notice to be cancelled		
Bond status		

LEGEND
PA—Producing Active
NPA—Non Potential Active
PI—Potential Inactive
NPI—Non Potential Inactive
Ab—Abandoned or No More Wells

71869-705 5-66 3M ② OSP

Ex. I - 21

FORM 103

SUBMIT IN DUPLICATE

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION

DIVISION OF OIL AND GAS

History of Oil or Gas Well

OPERATOR Pacific Lighting Service Company FIELD Aliso Canyon

Well No. IW 63, Sec. 34, T. 3N, R. 16W, SB B. & M.

Date June 8, 1973 Signed R. S. Magruder Jr.

P. O. Box 54790, Terminal Annex
Los Angeles, Calif. 90054 (213) 689-3561 Title Agent
(Address) (Telephone Number) (President, Secretary or Agent)

It is of the greatest importance to have a complete history of the well. Use this form to report a full account of all important operations during the drilling and testing of the well or during re-drilling, altering of casing, plugging, or abandonment with the dates thereof. Be sure to include such items as hole size, formation test details, amounts of cement used, top and bottom of plugs, perforation details, sidetracked junk, bailing tests, shooting and initial production data.

1972 Date	
8-6	Well drilled by Camay Drilling Company, Contractor, rig #8. All measurements taken from top of kelly bushing which was 15' above mat. Spudded well at 12:01 PM, 8-6-72, and drilled 11" hole to 922'.
8-7	Opened 11" hole to 17-1/2" from 40' to 705'.
8-8	TO CEMENT 13-3/8" SURFACE CASING: Ran 17 joints or 704.11 feet of 13-3/8", 48#, H-40, 8rd., ST&C, R-3, new seamless blank casing and cemented same at 699' with 534 sacks of Class "G" cement treated with 2% calcium chloride. Cement in place 12:30 AM. CASING DETAIL: All 17 joints or 699 feet, 13-3/8" fitted on bottom with Baker stab in shoe. Cut and recovered 13-3/8" casing, welded on Shaffer casing head and tested same to 3000# OK. Installed BOP.
8-9	Tested BOP to 1000# OK. Test witnessed and APPROVED BY ENGINEER FOR DIVISION OF OIL AND GAS.
8-10	Drilled 11" hole to 1270'. Pow-R-Drill #1 11" hole to 1288'.
8-11	Pow-R-Drill #1 11" hole to 1600'. Reamed 1482' to 1600' and directionally drilled 11" hole to 1778'.
8-12	Directionally drilled 11" hole to 2542'.
8-13	Directionally drilled 11" hole to 3153'.
8-14	Directionally drilled 11" hole to 3830'.
8-15	Directionally drilled 11" hole to 4405'.

1972

8-16 Directionally drilled 11" hole to 4540'.
Pow-R-Drill #2 11" hole to 4617'.

8-17 Reamed 4540' to 4617' and directionally drilled 11" hole to 5000'.

8-18 Directionally drilled 11" hole to 5192'.
Pow-R-Drill #3 11" hole to 5310'.

8-19 Pow-R-Drill #3 11" hole to 5351'.
Ream 5191' to 5351' and directionally drilled 11" hole to 5722'.

8-20 Directionally drilled 11" hole to 6100'.

8-21 Reamed 6060' to 6100' and directionally drilled 11" hole to 6447'.

8-22 Directionally drilled 11" hole to 6798'.

8-23 Ream 6123' to 6163' and directionally drilled 11" hole to 6950'.
Ran Dresser Atlas Induction Electrolog and recorded from 6937' to 699'.

8-24 Directionally drilled 11" hole to 7100'. Circulate and condition gas cut mud.
Ran Dresser Atlas Induction Electrolog and recorded from 7092' to 5600'.
Directionally drilled 11" hole to 7106'.

8-25 Directionally drilled 11" hole to 7190'.
TO CEMENT 8-5/8" CASING: Ran 172 joints or 7195' of 8-5/8", 36#, K-55 and N-80, Buttress thread, R-3, new seamless blank casing and cemented same at 7190' with 600 sacks Class "G" cement. Displaced with 2390 cu. ft. of mud to bump plug to place at 9:22 PM under 750# final pressure. Dropped plug and opened stage collar at 1919'. Pumped in 100 sacks Class "G" cement. Displaced with 690 cu. ft. mud. Did not bump plug; cement in place at 10:30 PM. Used Dowell bulk cement and power.

CASING DETAIL

Bottom 33 joints or 1386'	(7190' to 5804') N-80 fitted on bottom with Davis fill-up float shoe and at 7146' with Davis fill-up float collar.
Next 139 joints or 5804'	(5804' to Sfc.) K-55 Stage collar at 1919'.
Total 172 joints or 7190 feet.	

8-26 Removed BOP, cut and recovered 8-5/8" casing, installed secondary 8-5/8" packing and tested same OK with 5000# psig.
Reinstalled BOP, ran 7-5/8" bit to stage collar plug at 1913'.

8-27 Drilled out stage collar at 1919' and same took fluid under 1000# pressure.
Set Baker full bore cement tool at 2000' and tested casing OK under 1500#.
Reset tool at 1800' and pumped away. Stage collar not holding.
TO SQUEEZE STAGE COLLAR AT 1919' WITH CEMENT: Set Baker cement tool above collar at 1919' and stage cemented with 100 sacks of Class "G" cement. Final pressure 1500# psig; cement in place at 1:00 PM.

1972

8-28 Drilled out cement with 7-5/8" bit from 1859' to 1919'; tested casing with 1500# psig for 15 minutes OK, and cleaned out to 7080'.

TO TEST WATER SHUT-OFF ON HOLES IN 8-5/8" CASING AT 7060': Ran combination gun and tester on 5" drill pipe and shot 4-1/2" jet holes at 7060'. Set packer at 7000'. Opened tool at 11:10 AM for 1 hour test. Strong blow 15 minutes and dead in 25 minutes. Recovered 1000' rise of drilling fluid. Water shut-off not approved.

8-29 TO SQUEEZE HOLES IN 8-5/8" CASING AT 7060' WITH CEMENT: Ran squeeze tool and set same at 6951'. Squeezed holes with 100 sacks Class "G" cement mixed to 118#/cu. ft. slurry. Cement in place at 4:35 AM under 2500# psig.

Ran 7-5/8" bit with scraper above and drilled out cement from 7009' to 7060'. Tested casing OK with 1650# psig cement.

8-30 TO TEST WATER SHUT-OFF ON HOLES IN 8-5/8" CASING AT 7059': Ran Johnston combination gun and tester and shot four 1/2" jet holes at 7059'. Set packer at 7014' with tail to 7039'. Opened tool at 1:17 AM for one hour test. Medium blow for 5 minutes, dead balance of test. Recovered 300' drilling fluid rise in 5" drill pipe. Charts OK. Water shut-off approved by ENGINEER FOR DIVISION OF OIL & GAS.

TO TEST HOLES IN 8-5/8" CASING AT 7059': Ran squeeze tool on 5" drill pipe and set same at 6952'. Pumped 30 cu. ft. of fluid to obtain 2500# psig on holes. Held OK. Holes not taking fluid.

Drilled out cement 7111' to 7190'. Drilled out shoe and drilled 7-5/8" hole to 7623'.

8-31 Drilled 7-5/8" hole to 7331'. Left 3 bit cones in hole.
Ran Globe junk basket and recovered all cones.
Reamed 7-5/8" hole 7300' to 7331'.

9-1 Drilled 7-5/8" hole to 7390'.
Ran Dresser Atlas suite of logs.

9-2 TO CEMENT 6-5/8" BLANK LINER: Ran 301' of 6-5/8", 27.65#, K-55, R-3, Security flush joint, new seamless blank casing on 5" drill pipe and liner cementing tool and hung liner at 7072'. Cemented same at 7373' with 75 sacks of Class "G" cement, with .2 of 1% D13, mixed to 118#/cu. ft. slurry. Preceded cement with 30 cu. ft. of water and displaced with 722 cu. ft. of mud to bump plug under 3000# final pressure. Cement to place at 5:20 PM. Used Dowell cementing equipment and bulk cement.

9-3 Ran in to 7082' where bit stopped. Displaced mud in hole with salt water. Layed down drill pipe.

9-4 Finish laying down drill pipe, removed BOP and installed Christmas tree.

1972

9-5 Removed tree, reinstalled BOP and picked up drill pipe.

9-6 Ran spear on 3-1/2" and 5" drill pipe and attempted to stab into liner cementing tool. Lost spear in hole.
Ran socket and recovered spear.
Ran mill and milled up and pushed liner cementing tool with swab cups down hole to 7367'.

9-7 Ran Dresser Atlas cement Bond Log and Density Log.
Ran 5-5/8" bit with scraper above and cleaned out to 7367' EFFECTIVE DEPTH.

9-8 Lay down drill pipe and run Dresser Atlas Neutron Lifetime Log.
Removed BOP and installed Shaffer Tree.
RIG RELEASED 9:30 PM.

11-2 Moved in CPS and rigged up. Installed BOPE. Tested pipe rams with 3500 psi for 10 minutes, OK. Tested Hydril bag with 3400 psi for 10 minutes, OK.

11-3 Picked up 2-7/8" Seal-Lock tubing and ran 5-5/8" bit and 6-5/8" casing scraper. Tagged bottom at 7368'. Ran 8-5/8" Baker fullbore packer to 4427'.

11-4 Set fullbore packer at 4427' and tested from surface to 4427' with 3700 psi. Pressure fell off at a rate of 150 psi/hr. Made nine additional pressure tests as follows:

Test Interval	Results
Surface to 4488'	No good
" " 1848'	Held 3700 psi for 20 minutes, OK
" " 1943'	Held 3700 psi for 20 minutes, OK
" " 3192'	No good
" " 2567'	No good
" " 2261'	Held 3700 psi for 20 minutes, OK
" " 2440'	No good
" " 2347	Held 3625 psi for 20 minutes, OK
Surface to 2409'	No good

Leak isolated between 2347' and 2409'.

11-5 Crew off

1972

11-6 Rigged up Welex. Ran Cement Bond and collar logs 1200-3000'. Ran 8-5/8" Baker Model "C" bridge plug on fullbore packer. Set bridge plug at 2460'. Set fullbore at 2440' and tested bridge plug with 3700 psi for 15 minutes, OK. Pulled up and set fullbore at 2410'. Tested 2410'-2460' with 3800 psi for 20 minutes, OK. Pulled up and set fullbore at 2378'. Tested 2378'- 2460' with 3800 psi for 20 minutes, OK. Pulled up and set packer at 2318'. Tested 2318' - 2460', no good. Leak in collar at 2344' (CBL/CCL measurement). Broke down at 3200 psi and took fluid at a rate of 10 ft^3/minute at 1750 psi. Ran in to 2440' and dumped five sacks sand. Pulled up and set fullbore packer at 2194'. With 50 ft^3 fresh water ahead mixed and pumped 100 sacks Class "G" cement with 2% calcium chloride and 0.5% CFR-2. Displaced with 115 ft^3 salt water. Final pressure 1350 psi. Cement in place at 10:00 pm. Used Halliburton equipment.

11-7 Ran 7-5/8" bit and 8-5/8" casing scraper. Tagged cement at 2250'. Drilled and cleaned out cement stringers 2250'-2285' and hard cement 2285'-2337'.

11-8 Tested from surface to 2460' with 2750 psi, no good. Measured in and set fullbore at 2360'. Tested 2360'-2460' with 2700 psi for 15 minutes, OK. Pulled up and set fullbore at 2320'. Tested from surface to 2320' with 2525 psi for 15 minutes, OK. Tested 2320'-2460', no good. Broke down at 4550 psi and took fluid at a rate of 12 cu ft per minute at 1800 psi. Pulled up and set fullbore at 2164'. With 50 ft^3 fresh water ahead mixed and pumped 100 sacks Class "G" cement with 2% calcium chloride and 0.5% CFR-2. Displaced with 107 ft^3 salt water. Final pressure 3250 psi. Cement in place 11:20 pm. Used Halliburton equipment.

11-9 Ran 7-5/8" bit and 8-5/8" casing scraper. Tagged cement at 2238'. Drilled and cleaned out hard cement 2238'-2344'.

11-10 Tested from surface to 2460' with 2600 psi for 20 minutes, OK. Ran in with bridge plug retrieving tool. Backscuttled cement and sand, and pulled bridge plug. Rigged up Dresser Atlas. Jet perforated four 1/2" holes per foot 7198'-7210' (NLL/CCL measurement). Used 4" carrier and 17 gram charges. During perforating operations discovered junk in hole. Ran 7-5/8" bit and 8-5/8" casing scraper. Tagged top of liner at 7072'.

11-11 Ran 5-1/2" junk basket on Dresser Atlas Electric line. Could not work basket into liner. As basket was being pulled through BOPE rope socket parted. Made feeler run with electric line and tagged junk basket fish at 7056'. Ran overshot and guide shoe on tubing and recovered fish. No significant recovery in junk basket.

11-12 Crew off

1972

11-13 Ran 6-5/8" casing scraper to 7355'. Backscuttled 2-1/2 hours. Recovered 100-150 bbls drilling mud. Pulled up to 7045' and backscuttled 30 minutes. Ran Baker Model "D" production packer on Dresser Atlas Electric line and set same at 7044' (NLL/CCL measurement).

11-14 Rigged up to run safety valve and control line. Tested safety valve and 6800' of 1/4" control line with 5000 psi for 30 minutes, OK.

11-15 Ran safety valve and control line on tubing to 6750'. Tested safety valve and control line with 5000 psi for 15 minutes, OK. Made control line splice and continued in hole. Tested safety valve and control line through donut with 5000 psi for 15 minutes, OK. Landed tubing with 13000# on Model "D" packer. Tore out BOPE and installed production head. Tested safety valve and control line through head with 5000 psi for 30 minutes, OK. Tested donut seals through test port with 4500 psi for 10 minutes, OK. Set Shaffer back pressure valve in donut and tested through unibolt cap with 4500 psi for 10 minutes, OK.

TUBING DETAIL

2-7/8"N-80 Seal-Lock fatigue nipple	.60'
2-7/8" N-80 Seal-Lock pup joint	8.00'
2-7/8" N-80 Seal-Lock pup joint	12.00'
225 joints 2-7/8" J-55 Seal-lock tubing	7025.37'
2-7/8" Seal-Lock x 2-7/8" 8 rd N-80 X-over	1.20'
Page 3-1/2" type RTL safety valve with ported nipple	5.62'
3-1/2" 8 rd x 2-7/8" 8 rd J-55 X-over	1.20'
Baker Seal Assembly	7.70'
	7061.69'

Ex. I - 22

Due to the large file size, this exhibit is an excerpt. The native file of this document is available upon request.

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

Gavin Newsom, Governor
David Bunn, Director

September 19, 2019

Mr. Robert Dentici
Southern California Gas company
555 West 5th St. ML 17G4
Los Angeles, CA 90013

Dear Mr. Dentici:

REPORT OF ABANDONMENTS

On August 5, 2019, this office received well summaries for the plugging and abandonment of the following wells located in the Aliso Canyon field:

Fernando Fee 32E (037-21321)
Porter 30 (037-00717)
Porter 32A (037-21277)
Porter 32E (037-21363)
Porter 35 (037-00722)
Porter 40 (037-00727)
Porter 42C (037-21878)
Porter 45 (037-00732)

Sesnon Fee 2 (037-00648)
Sesnon Fee 4 (037-00650)
Sesnon Fee 5 (037-00651)
Sesnon Fee 6 (037-00652)
Sesnon Fee 7 (037-00653)
Sesnon Fee 8 (037-00654)

Standard Sesnon 11 (037-00763)
Standard Sesnon 12 (037-00764)
Standard Sesnon 14 (037-00766)
Standard Sesnon 16 (037-00768)
Standard Sesnon 25B (037-21323)
Standard Sesnon 3H (037-00756)
Standard Sesnon 44A (037-21455)

In accordance with California Code of Regulations (CCR) §3232 "The supervisor or the district deputy shall, within 10 days after the receipt of a written report of abandonment, furnish the owner or operator with a written final approval of abandonment, or a written disapproval of abandonment, setting forth the conditions upon which the disapproval is based." Due to the number of submissions and extensive operations detailed in these summaries, a determination cannot be made within the time prescribed by law.

If you have any questions or need additional information, please contact Mr. Eric Heaton, Engineering Geologist at (805) 937-7246.

Sincerely,

Patricia A. Abel
Coastal District Deputy

cc: Chrono/Well files/ Follow up

RAL RESOURCES AGENCY OF CALIFORN
DEPARTMENT OF CONSERVATION
DIVISION OF OIL, GAS & GEOTHERMAL RESOURCES
1000 S. Hill Rd, Suite 116 Ventura, CA 93003-4458
Phone:(805) 654-4761 Fax:(805) 654-4765

No. T **217-0614**

REPORT ON OPERATIONS

GAS STORAGE PROJECT
"Sesnon-Frew" - Modelo (Miocene-Eocene) Formation

Roberto (Bob) Dentici
Southern California Gas Company (S4700)
555 West 5th Street, ML 17G4
Los Angeles, CA 90013

Ventura, California
October 26, 2017

Your operations at well **"Sesnon Fee" 2**, A.P.I. No. **037-00648**, Sec. **33**, T. **03N**, R. **16W**, **SB** B.&M., **Aliso Canyon** field, in **Los Angeles** County, were witnessed on **10/24/2017**, by **Blake Foreshee**, a representative of the supervisor.

The operations were performed for the purpose of **inspecting the blowout prevention equipment and installation**.

DECISION: **APPROVED**

BF2/ap

Kenneth A. Harris Jr.
State Oil and Gas Supervisor

By
Patricia A. Abel, *District Deputy*

7-20-76 Ran 6.15" O.D. Servco mill to 3031' and milled to 3301'. Stopped rotation and ran to 3406' and hit Baker rubber packing element lost in hole from Retrieva-"D" packer. Pushed rubber to 8380' when tools stopped. (Took 50,000# over tubing weight with hydraulic jars barely working.) Circulated hole and started out.

7-21-76 Pulled out of hole. Ran 6" O.D. wireline junk basket while waiting on new mill. (Stopped at 8366'.) Made up Servco 6" O.D. flat-bottomed junk mill. Ran to 9237' and milled up rubber to 9237'. Circulated hole and started out.

7-22-76 Ran Baker 7" Retrieva-"D" packer on "GO" electric line to 9140' and set it. Ran "GO" casing patch on tubing and set across interval from 3226' to 3258'. Pulled 30 stands of tubing and shut down.

7-23-76 Finished pulling tubing and "GO" tools out of hole. Started in hole with Baker 80-32 anchor seal assembly; 10' blast joint; 2 7/8" O.D. x 1.81 "No-Go" nipple; 20' blast joint, Camco 2 7/8" KP.5 safety valve housing with "EH" valve closed, and 8 Camco 2 7/8" KBM mandrels; breaking off 2 7/8" tubing collars and replacing them with inspected ones, and testing the tubing string to 5000 psi for one minute.

7-24-76 Continued running tubing, changing collars and hydrotesting tubing. Landed Baker Seal Assembly in packer. Pulled 20,000# over tubing weight on seal assembly latch. Landed tubing with 5000# on packer. Shut well down.

7-25-76 Idle.

7-26-76 Removed B.O.P.E. Installed Christmas tree and tested to 5000 psi. Displaced polymer mud with waste lease salt water. Installed blanking plug in "No-Go" nipple and tested packer and seals to 2000 psi. Retrieved blanking plug. Rigged down and released rig.

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION

DIVISION OF OIL AND GAS

REPORT ON PROPOSED OPERATIONS No. P 276-154

Mr. P. S. Magruder, Jr., Agent
Southern California Gas Co.
P.O. Box 54790 Terminal Annex
Los Angeles, California 90054

Santa Paula, Calif.
May 20, 1976

DEAR SIR:

Your proposal to alter casing Well No. "SFZU" SF-2 (037-00648),
Section 33, T. 3N, R. 16W, S.B.B. & M., Aliso Canyon Field, Los Angeles County,
dated 5/13/76, received 5/17/76, has been examined in conjunction with records filed in this office.

THE PROPOSAL IS APPROVED PROVIDED THAT:

1. The drilling fluid used shall be of a quality and in sufficient quantity to control all subsurface conditions in order to prevent blowouts; and a reserve supply of this material shall be kept on hand to meet any emergency.
2. Blowout prevention equipment, at least of the Division of Oil and Gas Class III rating, shall be installed and maintained in operating condition at all times.
3. THIS DIVISION SHALL BE NOTIFIED TO WITNESS A PRESSURE TEST OF THE BLOWOUT PREVENTION EQUIPMENT BEFORE COMMENCING DOWNHOLE OPERATIONS.

NOTE: A COPY OF THIS APPROVAL SHALL BE POSTED AT THE WELL SITE PRIOR TO COMMENCING OPERATIONS.

Blanket Bond
MD:b

Copy [illegible] available.
[illegible]
See charts.

HAROLD W. BERTHOLE
~~JOHN F. MATTHEWS, JR.~~, State Oil and Gas Supervisor

By [signature], Deputy

25476-705 7-74 50M ⓓD OSP
OG 111

DIVISION OF OIL AND GAS
RECEIVED
MAY 17 1976
SANTA PAULA, CALIFORNIA

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION

DIVISION OF OIL AND GAS

Notice of Intention to Rework Well

This notice and indemnity or cash bond shall be filed, and approval given, before rework begins. If operations have not commenced within one year of receipt of the notice, this notice will be considered cancelled.

FOR DIVISION USE ONLY		
BOND	FORMS	
	114	121
BB	✓	—

DIVISION OF OIL AND GAS

In compliance with Section 3203, Division 3. Public Resources Code, notice is hereby given that it is our intention to rework well No. SESNON FEE #2, API No. _____, Sec. 33, T. 3N, R. 16W, S.B. B. & M., Aliso Canyon Field, Los Angeles County.

The present condition of the well is as follows:

1. Total depth. 9471'

2. Complete casing record, including plugs and perforations:

13 3/8" cemented 1594'
7" cemented 9245', WNSO 9153', squeezed and pressure tested to 1000 psi. Perforated 9208'-9190', 9180'-9172'
5" cemented 9467', cement plug 9429', top of liner 9237' squeezed lap at 9237' - pressure tested O.K. Perforated 9330'-9322', 9316'-9308'.

3. Present producing zone name SESNON Zone in which well is to be recompleted -

4. Present zone pressure 2600 psi New zone pressure -

5. Last produced S.I. Gas Storage Well _____ _____ _____
(Date) (Oil, B/D) (Water, B/D) (Gas, Mcf/D)

or

6. Last injected _____ _____ _____ _____
(Date) (Water, B/D) (Gas, Mcf) (Surface pressure, psig.)

The proposed work is as follows:

1. Move in rig, kill well, install B.O.P.E. and pressure test.
2. Pull tubing. Clean out to 9429'. Run Neutron lifetime and cement bond logs.
3. Perform any indicated remedial work. Install new wellheads.
4. Pressure test 7" casing. Perform any indicated remedial work.
5. Perforate Sesnon Zone sands as indicated by logs.
6. Run packer, tubing, safety valve and gas lift valves.

It is understood that if changes in this plan become necessary we are to notify you immediately.

Address P. O. Box 3249, Terminal Annex
(Street)
Los Angeles California 90051
(City) (State) (Zip)
Telephone Number (213) 689-3561

SOUTHERN CALIFORNIA GAS COMPANY
(Name of Operator)
By P. S. Magruder Jr. 5/13/76
(Name) P. S. Magruder, Jr. (Date)
Type of Organization Corporation
(Corporation, Partnership, Individual, etc.)

OG107 (12-73-GSR1-15M)

FORM 157

NI/

STATE OF CALIFORNIA
DEPARTMENT OF CONSERVATION
DIVISION OF OIL AND GAS

REPORT ON PROPOSED CHANGE OF WELL DESIGNATION

830 North La Brea Avenue
Inglewood, California

September 25, 1968

~~Mr.~~ Mr. C. G. Nelson, Agent
Getty Oil Co., Operator
P. O. Box 811
~~Agent for~~ Ventura, California 93001

DEAR SIR:

Your ~~request dated~~ letter dated August 26, 1968, relative to change in designation of well(s) in Sec. 32,33,34, T. 3 N., R. 16 W., S.B. B. & M., Aliso Canyon field, Los Angeles County, District No. 1, has been received;

and in accordance with Section 3203, Public Resources Code, reading in part as follows:

> "* * * The number or designation by which any well heretofore drilled has been known, and the number or designation specified for any well in a notice filed as required by Section 3203, shall not be changed without first obtaining a written consent of the Supervisor."

the proposed change in designation is hereby authorized as follows: (Formerly owned by Porter Sesnon, Et Al)

Old Designation			New Designation		
Sec. 32:	"Sesnon Fee"	4	Sec. 32:	"SFZU"	SF-4 (037-00650)
	"	6		"	SF-6 (037-00652)
Sec. 33:	"	1	Sec. 33:	"	SF-1 (037-00647)
	"	2		"	SF-2 (037-00648)
	"	3		"	SF-3 (037-00649)
	"	5		"	SF-5 (037-00651)
	"	7		"	SF-7 (037-00653)
	"	8		"	SF-8 (037-00654)
Sec. 34:	"Porter Fee"	1	Sec. 34:	"	PF-1 (037-00644)
	"	2		"	PF-2 (037-00645)
	"	3		"	PF-3 (037-00646)

ag
cc: F. E. Kasline
Production Dept.
Conservation Committee

F. E. KASLINE
~~E. R. MURRAY-AARON~~
State Oil and Gas Supervisor

By Wm. C. Bailey
Deputy Supervisor

△ SPO

Ex. I - 23

FORM 103
CALIFORNIA STATE PRINTING OFFICE

SUBMIT IN DUPLICATE

STATE OF CALIFORNIA
DEPARTMENT OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

History of Oil or Gas Well

OPERATOR TIDE WATER ASSOCIATED OIL COMPANY FIELD ALISO CANYON

Well No. Standard-Seamon 2-17, Sec. 26, T. 3 N, R. 16 W, S.B. B. & M.

Signed F. C. Foster
p

Date October 13, 1952 Title Agent
(President, Secretary or Agent)

It is of the greatest importance to have a complete history of the well. Use this form in reporting the history of all important operations at the well, together with the dates thereof, prior to the first production. Include in your report such information as size of hole drilled to cementing or landing depth of casings, number of sacks of cement used in the plugging, number of sacks or number of feet of cement drilled out of casing, depth at which cement plugs started, and depth at which hard cement encountered. If the well was dynamited, give date, size, position and number of shots. If plugs or bridges were put in to test for water, state kind of material used, position and results of pumping or bailing.

Date

1952

7/20 Swabbed 175 barrels of muddy water. Salinity at 4:00 PM, 492 grains per gallon. Fluid level 2000'. Pulled tester loose at 11:00 PM and found fluid level at 1500'. Water sample above tester, 554 grains per gallon.

7/21 Ran bit and cleaned out to 11,000'. Found sand bridge from 10,430' to 10,435'. Had good gas showing on ditch while circulating returns from 10,430'. Ran McCullough Neutron Log. Pls #1 found to be [illegible]

7/22 Hung 3-1/2" drill pipe at 9548' and plugged with 100 sacks Colton Hi-Temperature Cement. Final pressure 800#. Time 11:30 AM. B.J. Service. Located top of plug at 9234' after standing 6 hours. Ran McCullough magnetector and checked aluminum section at 8433' to 8523'. Started milling aluminum section at 8490'.

7/23 Milled aluminum section from 8490' to 8516'.

7/24 Found bottom of aluminum section at 8516'. Pulled up and started milling aluminum section at 8476' and milled to 8490'.

7/25 Ran 10-5/8" Baker scraper and scraped from 8476' to 8516'.

7/26 Ran Booth Ross whipstock on 3-1/2" drill pipe and set on stub of 7" casing at 8516' with tailpipe to 8531'. Cemented in place with 50 sacks of Colton Hi-Temperature Cement. Time 5:45 AM. B.J. Service.

7/27 Standing cemented. Located top of cement at 8438'.

7/28 Cleaned out cement from 8433' to 8507' and redrilled to 8535' with 6" bit.

7/29 Redrilled 6" hole from 8535' to 8669'. Ran Schlumberger electric log at 8663'. Hole following alongside 7" casing.

7/30 Hung 2-1/2" tubing at 8656' and plugged well with 100 sacks Colton Hi-Temperature cement. Final pressure 700#. Time 6:00 AM. B.J. Service. At 4:00 PM located top of cement at 8250'. Cleaned out to 8273' and lost circulation. Ran Halliburton squeeze tool and located hole in 7" casing at 5238'.

7/31 Set Halliburton squeeze tool at 4985' and pumped in 100 sacks Victor Hi-Temperature cement through hole at 5238'. Final pressure 400#. Time 8:30 AM. Halliburton Bulk Method. At 1:30 PM applied 1100# pressure without loss. Located top of cement at 4996' and cleaned out hard cement to 5256', then found stringers of cement to 5286'.

8/1 Cleaned out cement from 8278' to 8359'. Closed rams and applied 1250# pressure for 15 minutes without loss. Cleaned out cement from 8359' to 8330' and lost circulation. Ran Halliburton shoe squeeze tool on 3-1/2" drill pipe and set at 4955'. Displaced fluid easily with 800# pressure. Mixed 150 sacks of Colton Slow Cement and displaced with 227 cu. ft. mud. Final pressure 500# which bled to 0#. Time 6:00 PM. Halliburton Bulk Method.

8/2 Standing cemented. Located top of cement at 4955'.

Ex. I - 24

History - Mission Adrian #1-B, Aliso Canyon

19

10-08 Set Baker retrieva-D packer at 7190'. Attempted to pressure test seals and packer - leak -

10-10 Set Baker "C" bridge plug at 7150' and capped with sand 7132'.

10-11 Baker fullbore - found leak 1594'-1596'. Ran casing inspection log 7100' - surface, leak showed 1594'-1596'.

10-12 Set Model "C" B. plug 1721' - sand to 1709'. Equalized 67 cu. ft. "G" Neat - B. Head squeezed 62 cu. ft. - F.P. 800 psi

10-13 DOC 1585'-1600' - Leaked 400 psi - Equalized 100 cu. ft. "G" Neat - 92 cu. ft. away DOC 1580'-1601' - 1000 psi B. down

10-14 Equalized 100 cu. ft. "G" + 3% Cacl2 Squeeze away 80 cu. ft. DOC 1500'-1608' Broke at 1200 psi - Equalized 100 cu. ft. "G" + 3% Cacl2 - squeezed away 85 cu. ft.

10-15 DOC 1604'-1608' - Leaked 1250 psi. Equalized 108 cu. ft. "G" + 3% Cacl2 F.P. 2600 psi - DOC 1296'-1620' B. down 1150 psi - Equalized 58 cu. ft. "G" Neat - squeezed 47 cu. ft. F.P. 1200 psi

10-16 DOC 1578'-1630' - leaked 1250 psi. Set drillable retainer 1546' - squeezed away 38 cu. ft. Cal seal F.P. 2600 psi

10-17 Drilled out cement and retainer.

10-18 Leaked 1250 psi - set drillable retainer 1548' - squeezed 53 cu. ft. "G" + 10% Cal seal F.P. 2600 psi, Rig released.

1980

6-18 Unlanded 8-5/8" casing

6-21 Backed off 8-5/8" at 180' (138' casing) Ran 4 new joints 8-5/8" casing, Top 40# N-80, 3 - 36# N-80 screwed in - P. tested 4000 psi - cut off casing

6-24 Drilled out cement and continued.

6-27 Ran full bore set 1486' - B. down 16 cu. ft. at 1800 psi - 100 sacks "G" + 10% Cal seal - circulation 8-5/8" x 13-3/8" annulus stopped pumping

6-28 DOC 1547'-1599' - 1300 psi bled off to 1100 psi in 10 minutes - set full bore 1486' - B. down 2000 psi - 20 cu. ft./minute 100 sacks "G" + 10% Cal seal - Displaced 2000 psi dropped to 1200 psi in 1 minute.

6-[illegible] DOC 1549'-1620' - 1300 psi lost 200 psi in 20 minutes - Ran full bore set 1486' - 12 cu. ft./minute at 1900 psi 100 sacks "G" + Cal seal - left 10 cu. ft. inside casing 2000 psi dropped to 1200 psi when stopped pumping

7-01 DOC 1466'-1576' tested - no entry

7-09 Ran 42' Pengo casing patch - set while running in well - left lower pack-off in well - pushed to 7180'

7-10 Set casing patch 1578'-1620'

8-17 Recovered top seal from casing patch - recovered balance of casing patch

8-18 Left bottom seal in well

8-19 Pushed bottom seal to 7190'

8-20 Ran casing patch which stopped at 30'

8-21 Ran 7.7" tapered mill - 24' - 205' and 1513'-1669'

8-22 Set casing patch 1540'-1622'

Well again leaking at 1596' 500 Mcf/Day
Likely both seals are leaking

7347'-5323'	40#	N-80	D.D. 7.6"
5323'-Surface	36#	N-80	D.D. 7.7"
Top joint	40#		D.D. 7.6"

6-5/8" 24# K-55 LT&C O.D. collars 7.39"

Major Costs

Rig	$ 80,000	
Wellheads	10,000	
Inner string	180,000	
Tubing	35,000	
Fittings for tubing	5,000	
BOPE	25,000	
Cementing	10,000	
Fishing	5,000	
V. Trucks	5,000	
Trucking	10,000	
Wellhead	2,500	
Supervision & Ad	15,000	
Contingency & Miscellaneous	32,500	
Total	$ 420,000	For cementing leak and running inner string
Completion fluid	20,000	
Grand Total	$ 440,000	

Set 3rd casing patch

Rig	$ 60,000	
BOPE	15,000	
Completion fluid	20,000	
Cementing	10,000	
Fishing	5,000	
V. Trucks	5,000	
Wellhead	500	
Supervision & Ad	9,000	
Casing patch	20,000	Set same 1606'-1554'
Contingency & Miscellaneous	15,500	
	$ 160,000	

Ex. I - 25

SOUTHERN CALIFORNIA gas COMPANY

INTEROFFICE CORRESPONDENCE

TO B. F. Jones
P. S. Magruder Jr.
D. S. Smiley

FROM A. L. Colbert

DATE June 26, 1979

SUBJECT Daily Well Report for Mission Adrian #1-B, Aliso Canyon

6-25-79

-0- Day. Moving Camrich rig from Porter #42-C to Mission Adrian #1-B.

6-26-79

-0- Day. Continued moving Kenai-Camrich rig to Mission Adrian #1-B wellsite and rigging up.

6-27-79

-0- Day. Rigging up.

6-28-79

-0- Day. Rigging up.

6-29-79

-0- Day. Rigging up.

6-30-79

-0- Day. Rigged up. Spudded in at 1:00 p.m., June 30, 1979. Drilled 17 1/2" hole from 57' to 210' with bit #1. Pulled out and picked up shock sub. Drilled 17 1/2" hole to 238' with bit #1.

Survey at 175' 1° N 89 W

Mud wt. 66#, Vis 38 sec., W.L. 11.4cc., sand 1/2%, solids 5%

6:00 a.m. Drilling ahead at 342'.

7-1-79

1st Day. Drilled 17 1/2" hole from 238' to 591' with bit #1.

Survey at 536' 1° S 89 W, V.D. 596.80', S 2.71, W 11.99

Mud wt. 68#, Vis 60 sec., W.L. 11.2cc., sand 1%, solids 6%

6:00 a.m. 645'. Drilling ahead with bit #2

Daily Well Report for Mission Adrian #1-B, Aliso Canyon

7-2-79

2nd Day. Drilled 17 1/2" hole from 591' to 859' with bit #2

Survey at 779' 1° 15' S 72 W, V.D. 778.75, S 6.16, W 18.88

Mud wt. 71#, Vis 50 sec., W.L. 11.4cc., sand 1%, solids 8%

6:00 a.m. Drilling ahead at 931' with bit #2.

7-3-79

3rd Day. Drilled 17 1/2" hole from 859' to 1,014' with bit #2. Ran 26 joints of K-55, 54.5# Buttress casing with Baker shoe at 1,014' stop ring at 972' and cemented with 800 cu.ft. of class "G" cement mixed with 8% gel and 3% calcium chloride , followed by 200 sacks of class "G" cement mixed with 3% calcium chloride. Cement in place at 11:45 p.m., 7-3-79. Bumped plug with 400 psi.

Survey 967' 3° 30' S 71 W, V.D. 966.59, S 8.82, W 22.90

Mud wt. 70#, Vis. 60 sec.

6:00 a.m. Welding on 13 5/8", 5,000 psi well head

7-4-79

4th Day. Cut off conductor and 13 3/8" casing. Welded on 13 5/8", 5,000 psi casing head. Pressure tested to 1,500 psi. Inspected with gamma ray device (O.K.). Installed class III 12", 5,000 psi BOPE. Set Johnston bridge plug at 60'. Tested 4 1/2" pipe rams.

6:00 a.m. Testing BOPE

7-5-79

5th Day. Tested complete shut off rams, 4 1/2" pipe rams, choke and kill manifold to 2,700 psi with water for 20 minute test. Tested Hydril to 2,000 psi with water, witnessed by D.O.G. Attempted to test complete shut off rams with nitrogen. Found leak in 13 3/8" casing. Removed BOPE and tightened 13 3/8" 2 turns at 10,000 ft. lbs. torque. Reinstalled BOPE and retested with nitrogen and casing leaked at 1,400 psi.

6:00 a.m. Removing BOPE

7-6-79

6th Day. Pressure tested blind rams and choke manifold with 2000 psi for 20 minutes with water.
Tested with nitrogen and found leak in 13 3/8" casing. Removed Bridge Plug and cut off 13 5/8" casing head. Backed off and recovered casing at first collar and found bad pin casing. Installed new 13 3/8" joint and torqued to 6000 Ft. lbs. Butt welded 13 5/8" well head and x-rayed weld.

6:00 a.m. Pressure testing with nitrogen.

7-7-79

7th Day. X-rayed well head. Nippled up B.O.P.E. and tested blank rams 4 1/2" pipe rams and Hydril to 2000 psi. Made up drilling assembly. Ran in and drilled out cement to 1,012'.

7-8-79

8th Day. Rig down for repairs.

7-9-79

9th Day. Finished Master Clutch Repair. Changed Hydril rubber. Drilled out shoe at 1,014' and drilled 12 1/4" hole to 1,173' with Bit #3.

Surveys: 1,082', 4°, S83W
1,210', 5°45, S74W, T.V.D. 1208.88 S-12.69',W-40.90

Mud: 66#, 45 sec., 10.2cc.,sand 1/4%, solids 5%

6:00 a.m. 7-10-79 Drilling ahead at 1,256' with Bit #3.

7-10-79

10th Day. Drilled 12 1/4" hole 1,173' to 1,296' with Bit #3. Made up and ran Dyna-Drill on 2 1/2° kick sub. Run #1 Dyna-Drilled 1,296' to 1,401' with Bit # Bit #4. Dyna-Drill stopped working after 3 1/2 hours of operation.

Surveys: 1,272', 6°15', S80W
1,316', 5°30', S71W
1,347', 4°30, S58W
1,377, 3°15, S56W, T.V.D. 1375.12, S-17.55,W-55.71

Mud: 68#, 48sec., 8.2cc., sand 1/4%, solids 6%

6:00 a.m. 7-11-79 Dyna-Drilling (Run #2) at 1,447' with Bit #5.

Daily Well Report for Mission Adrian #1, Aliso Canyon

7-11-79

11thDay. Made up and ran Dyna-drill #2 and Bit #5. Dyna-Drilled 12 1/4" hole 1,401' to 1,667'. Running in hole with Bit #6 on drilling assembly.

Surveys: 1,407' 3°, S31W
1,439' 3°, So4E
1,470' 4°, S12E
1,502' 2°45',S18E
1,534' 1°45',S03W
1,564' 1°30',S41E
1,596' 2°15',S64E
1,627' 3°45',S65E, T.V.D. 1624.83, S-27.44, W-53.71

Mud: 68#, 43sec., 7.4cc., sand 1/4%, solids 6%.

6:00 a.m. 7-12-79. Drilling ahead at 1,747' with Bit #6.

7-12-79

12th Day. Directionally drilled 12 1/4" hole 1,667' to 2,118' with Bit #6. Running in with Bit #7.

Surveys: 1,723' 6° ,S59E
1,816' 6°15,S56E
1,909' 6°15,S54E
1,999' 6°30,S54E
2,093' 6°30,S55E
2,183' 6°15,S55E, T.V.D. 2177.88, S-60.37, W-5.01

Mud: 71#, 50sec, 6.4cc., sand 1%, solids 9%

6:00 a.m. 7-13-79. Drilling ahead at 2,300' with Bit #7.

7-13-79

13th Day. Directionally drilled 12 1/4" hole from 2,118' to 2,391' with bit #7. Dyna-drilled 12 1/4" hole from 2,391' to 2,456' with dyna-drill #3 and bit #8. Pulling out to change kick sub from 2 1/2° to 1 1/2°.

Surveys: 2,275' 6° 30', S 55 E
2,366' 5° , S 53 E
2,416' 4° 45', S 81 E
2,447' 6° , N 88 E, TVD 2,440.57', S-73.32', W- 17.14'

Mud wt. 72#, Vis. 48 sec., W.L. 6cc., sand 1%, solids 9%

6:00 a.m. Dyna- drilling 12 1/4" hole at 2,518'.

7-14-79

14th Day. Dyna-drilled 12 1/4" hole from 2,456' to 2,610' with bit #8 RR, Run #4, Dyna-drill #2. Pulled out, changed bits and kick sub from 1 1/2° to 2°. Dyna-drilled 12 1/4" hole from 2,610' to 2,733' with bit #9, run 5, Dyna-drill #2.

Surveys:	2,447'	6° ,	N 88 E	
	2,478'	6° 30',	N 77 E	
	2,510'	6° 15',	N 69 E	
	2,538'	6° 15',	N 61 E	
	2,570'	6° ,	N 53 E	
	2,601'	6° 15',	N 44 E	
	2,631'	7° 30',	N 34 E	
	2,662'	7° 45',	N 26 E	
	2,693'	7° 45',	N 14 E	
	2,726'	9° ,	N 04 E	TVD 2717.54, S-51.17, E- 38.50

Mud wt. 71#, Vis 44 sec., W.L. 6.2cc., sand 1/2%, solids 9%

6:00 a.m. T. D. 2,766' Pulling dyna-drill.

7-15-79

15th Day. Dyna-drilled 12 1/4" hole from 2,733' to 2,766' with bit #9 run #5, Dyna-drill #2. Ran drilling assembly, reamed from 2,394' to 2,766', directionally drilled 12 1/4" hole from 2,766' to 2,868' with bit #10. Pulling out for Dyna-drill.

Surveys:	2,813'	9° 45',	N 20 E	
	2,843'	9° 15'	N 21 E	TVD 2,832.97, sec. 32' S- 32.66, E- 43.18

Mud wt. 71#, Vis 42 sec., W.L. 7.2cc., sand 1/4%, solids 8%

6:00 a.m. Dyna-drilling 12 1/4" hole at 2,868' with bit #11, run #6, Dyna-drill #2.

7-16-79

16th Day. Dyna-drilled 12 1/4" hole from 2,868' to 2,998' with bit #11.

Surveys:	2,896'	9°	N 11 E	
	2,926'	8° 45'	N	
	2,958'	10°	N	
	2,978'	11°	N 11 W	TVD 2,966.18, Sec. 11, E 46.26, S 11.12

Mud wt. 70#, Vis. 40 sec., W.L. 7 cc., Sand nil, solids 6%

6:00 a.m. Running in hole with Eastman D.O.T. guide tool.

7-17-79

17th Day. Dyna-drilled 12 1/4" hole using Eastman "D.O.T." guidance tool from 2,998' to 3,126' with bit #12.

Survey: 3,182' 13° 25' N 4 E, Vert. 3,165.63', N 31.74' E 45.51', Sec 31

Mud wt. 70.5#, Vis. 44 sec., W.L. 6.8cc., solids 6 1/4%, sand trace

6:00 a.m. Drilling at 3,230'.

7-18-79

18th Day. Directionally drilled 12 1/4" hole from 3,126' to 3,549' with bit #13.

Surveys:	3,182'	13° 15'	N 4 E	
	3,272'	14° 45'	N 5 E	
	3,396'	16° 45'	N 4 E	
	3,524'	18° 45'	N 2 E	TVD 3,494.28, N 126.07, E 53.40, Sec 126

Mud wt. 71#, Vis 48 sec., W.L. 7.0cc., sand 1/4%, solids 7%

6:00 a.m. Surveying at 3,674'.

7-19-79

19th Day. Directionally drilled 12 1/4" hole from 3,549' to 3,797' with bit #14, and to 3,987' with bit #15.

Surveys:	3,649'	20° 45'	N 01 E	
	3,772'	23°	N 01 E	
	3,871	22° 15'	N 02 E	
	3,962'	21° 30'	N 04 E	TVD 3,901.48, N 287.79', E 52.39' Sec 288.38

Mud wt 70#, Vis 42 sec., W.L. 7.0cc., solids 7%, sand trace

6:00 a.m. Surveying at 4,112'

7-20-79

20th Day. Directionally Drilled 12 1/4" hole from 3,797' to 4,237' with bit #15 and to 4,415' with bit #16.

Surveys:	4,087'	21° 15'	N 4 E	
	4,212'	20° 45'	N 6 E	
	4,303'	22°	N 8 E	
	4,395'	24° 30'	N 8 E	TVD 4,303.75', N 447.01, E 68.52, sec. 447.19

Mud wt. 70#, Vis 42 sec., W.L. 6.8cc., solids 7%, sand 1/4%

6:00 a.m. Tripping at 4,423'.

7-21-79

21st Day. Directionally drilled 12 1/4" hole from 4,415' to 4,423' with bit # 16 and to 4,575' with bit #17.

Surveys:	4,520'	25° 30'	N 8 E	
	4,549'	26°	N 7 E	TVD 4,443.16', N 511.81, E 77.51, Sec 512.11

Mud wt. 70#, Vis 40 sec., W.L. 6.8cc., sand trace, solids 8%, oil 7%

6:00 a.m. Running in hole with Dyna-drill.

7-22-79

22nd Day. Dyna-drilled 12 1/4" hole using Eastman "D.O.T." guidance tool from 4,574' to 4,604' with bit #18. Stuck pipe at 4,604' at 8:00 a.m.. Pipe free at 10:00 a.m. Pulled out of hole. Rig had 2 hours down time changing out Rotary table. Ran drilling set up.

Mud wt. 70#, Vis. 43 sec., W.L. 6.4cc., sand trace, solids 8%, oil 7%.

6:00 a.m. Drilling at 4,640'.

7-23-79

23rd Day. Directionally drilled 12 1/4" hole from 4,604' to 4,668' with bit #18. Pulled out and repaired rig 8 hours (installed #3 engine and changed rotary table). Ran in with bit #19.

Mud wt. 70#, Vis. 45 sec., W.L. 6.1cc., Sand trace, solids 8%, Oil 6%

Survey at 4,643' 25° 45' N 4 E, TVD 4,612.40', N 593.36, E 84.64, Sec. 593.75

6:00 a.m. Circulating for survey at 4,840', bit #19.

Daily Well Report for Mission Adrian #1-B, Aliso Canyon

7-24-79

24th Day. Directionally drilled 12 1/4" hole from 4,663' to 4,949' with Bit #19. Ran in with Dyna Drill and Bit #19 to 1,000' repairing engine. (3 hours lost time.)

Mud weight: 70#, vis. 45 sec., W.L. 6.4, sand trace, solids 8%, oil 5 %.

Survey: 4,924' 25 3/4° N 6°E, VD 4,780.64 , Section 675.40 , N 674.64 , E 92.11

6:00 a.m. Dyna Drilling at 4,972' with Bit #19.

7-25-79

25th Day. Dyna-drilled 12 1/4" hole with guidance tool from 4,949' to 5,006' with bit #20 and to 5,082' with bit #21.

Mud wt. 70#, Vis. 43 sec., W.L. 5.0cc., Sand trace, Solids 6%, Oil 5%

Survey 5,039' 23° 30', N 1 3/4 W, VD 4,885.24', Sec 722.79, N 722.31, E 94.03

6:00 a.m. 5,082' Running in with bit #22.

7-26-79

26th Day. Directionally drilled 12 1/4" hole from 5,082' to 5,573' with bit #22.

Mud wt. 70#, Vis. 45 sec., W.L. 5.5cc., Sand trace, Solids 7%, Oil 5%

Survey 5,644' 22° 45', N 5 1/2 W, VD 5,441.99', Sec 958.12, N 958.08, E 71.10

6:00 a.m. Surveying at 5,730'.

7-27-79

27th Day. Directionally drilled 12 1/4" hole from 5,573' to 5,699' with bit #22 and to 5,880' with bit #23.

Mud wt. 70#, Vis. 46 sec., W.L. 5.6cc., Sand 1%, Solids 7%, Oil 5%

Survey: 5,953' 23° N 5 W, VD 5,726.31, Sec. 1078.47, N 1078.47, E 60.87

6:00 a.m. Depth 6,000', drilling ahead

7-28-79

28th Day. Directionally drilled 12 1/4" hole from 5,880' to 6,109' with bit #23, and to 6,240' with bit #24

Mud wt. 73#, Vis 43 sec., W.L. 5.8cc., Sand 1%, Solids 8%, Oil 4%

Survey: 6,205' 23° 15' N 5 1/2 W VD 5,957.95, Sec. 1,177.30, N 1177.34, E 52.44

6:00 a.m. 6.260', tripping for bit #25

7-29-79

29th Day. Directionally drilled 12 1/4" hole from 6,240' to 6,260' with bit #24 and to 6,477' with bit #25.

Mud wt. 71#, Vis 42 sec., W.L. 5.6cc., Sand 1%, Solids 7%, Oil 4%

Survey: 6,452' 24° N 4 1/2 W, VD 6,184.35, Sec. 1,175.63, N 1,275.38, E 44.70

6:00 a.m. 6,477', reaming to bottom with bit #26.

7-30-79

30th Day. Directionally drilled 12 1/4" hole from 6,477' to 6,575' with bit #26. Reamed from 5,257' to 6,477'.

Surveys: 6,515' 24° 15' N 4 W
6,550' 24° 15' N 4 W, TVD 6,273', Sec. 1,316.66', N 1,315.80', E 41.79'

Mud wt. 72#, Vis 42 sec., W.L. 4.4cc., Sand 1/2%, Solids 8%

6:00 a.m. Drilling 12 1/4" hole at 6,603' with bit #27.

7-31-79

31st Day. Directionally drilled 12 1/4" hole from 6,575' to 6,790' with bit #27.

Surveys: 6,643', 22° 45', N 4 W
6,706', 22° , N 4 W
6,765', 21° 15', N 4 W, TVD 6,472.15', Sec. 1,399.19', N 1,398.42'. E 36.01'

Mud wt. 74#, Vis 46 sec., W.L. 4.1cc., Sand 1/2%, Solids 9%, Oil 4%

6:00 a.m. Drilling ahead at 6,835' with bit #28.

8-1-79

32nd Day. Directionally drilled 12 1/4" hole from 6,790' to 6,950' with bit #28. Tripped for bit. Reamed 6,920' to 6,950'.

Surveys: 6,828' 21°, N 4 W
6,925' 21° 15' N 4 W, TVD 6,621.40', Sec. 1,456.67', N 1,455.95' E 31.99'

Mud wt. 77#, Vis 45 sec., W.L. 4.2cc., Sand 1/2%, Solids 11.5%, Oil 3.5%

6:00 a.m. Drilling ahead at 7,042' with bit #29.

8-2-79

33rd Day. Directionally drilled 12 1/4" hole from 6,950' to 7,100' with bit #29 and to 7,130' with bit #30.

Surveys: 7,017', 20° 45' N 3° 30' W
7,109', 20° 30', N 4 W, TVD 6,793.38, Sec. 1,522.05, N 1,521.20', E 27.71'

Mud wt. 77#, Vis 48 sec., W.L. 4.4cc., Sand 1/2%, Solids 12%, Oil 3%

6:00 a.m. Drilling ahead at 7,257' with bit #30.

8-3-79

34th Day. Directionally drilled 12 1/4" hole from 7,130' to 7,347' with bit #30. Circulated and conditioned hole for logs.

Surveys: 7,232', 20° 30', N 1 W
7,322', 21° , N 1 W TVD 6,992.75', sec. 1,596.92', N 1,596.41', E 25.27'
7,347', 21° , N 1 W (extrapolated) TVD 7,016.09', Sec 1,605.88', N 1,605.37', E 25.11'.

Mud wt. 77#, Vis 47 sec., W.L. 4.5cc., Sand 1/2%, Solids 12%, Oil 3%

6:00 a.m. Pulling out of hole for logs.

8-4-79

35th Day. Circulated for logs. Pulled out of hole. Ran Schlumberger Dual Induction Sonic and FDC which stopped at 7,162'. Ran Dual Induction SFL log and recorded from 7,327' to 1,014'. Ran in with drilling assembly and cleaned out to 7,347'. Circulated for logs. Pulling out.

Mud wt. 77#, Vis 46 sec., W.L. 4.5cc., Sand 1/2%, Solids 12%, Oil 3%

6:00 a.m. Schlumberger logging from 7,339' to 1,014' with FDC, CNL and GR.

8-5-79

36th Day. Continued pulling out of hole. Schlumberger ran Gamma Ray, CNL, FDC logs and recorded from 7,339' to 1,012', dipmeter from 7,332' to 1,012', Sonic and Gamma Ray from 7,332' to 1,012'. Rigging down loggers.

Mud wt. 77#, Vis 47 sec., W.L. 4.6cc., Sand 1/2%, Solids 12%, Oil 3%

6:00 a.m. Circulating at 7,347' for casing.

Daily Well Report for Mission Adrian #1-B, Aliso Canyon

8-6-79

37th Day. Laid down non-magnetic drill collar, Ran in with drilling assembly and bit #30RR. Cleaned out fill from 7,339' to 7,347'. Circulated and conditioned for casing. Worked pipe through tight hole from 3,266' to 2,723' where drilling assembly became stuck. Jarred up and down. Rigged Dia-Log Freepoint and string shot. Backed off at 2,366'. Length of fish 357'. Rigged down Dia-Log. Pulled out, picking up fishing tools.

6:00 a.m. Fishing

8-7-79

38th Day. Attempted to screw into fish at 2,366' without success. Ran back to 2,366' for second attempt. Ran in to 2,410' where drill string stopped. Pulled out, made up and ran Midway 11" skirted sub. Screwed into fish at 2,426'. Jarred fish loose, chaining out of hole.

6:00 a.m. Running in hole with bit, near bit, stab, 1-DC, stab, to condition mud for casing.

8-8-79

39th Day. Finished chaining out with fish. Laid down and loaded out fishing tools. Laid down 7" drill collars and stabilizers. Ran 12 1/4" bit, 2 stabilizers and one drill collar to 7,347'. Circulated and conditioned mud. Pulled out and laid down tools. Rigging up to run casing.

Mud wt. 77#, Vis. 46 sec., W.L. 4.2cc., Sand 1/2%, Solids 12%, Oil 2 1/2%

6:00 a.m. Pulling bit guide.

8-9-79

40th Day. Strung 10 lines. Pulled bit guide from 13 3/8" head. Running 8 5/8" casing.

6:00 a.m. Cementing 8 5/8" casing.

Daily Well Report for Mission Adrian #1-B, Aliso Canyon

8-10-79

41st Day. Ran 49 Jts. of 8 5/8" 40# N-80 and 130 Jts. of 8 5/8" 36# N-80 all with buttress thread. Total of 7,353.82' on hook. B&W float shoe landed at 7,347', B&W float collar at 7,220'. Shoe, bottom three jts. and float collar had thread-lock applied. Two centralizers and three clusters of scratchers installed on bottom three joints. Centralizers installed on every other collar up to 1,000'. Circulated casing. Dowell pumped 500 cu.ft. "CW7" ahead of 1,200 cu.ft. of 1-1 lite-poz 7, blended with 1% "D-65" and 0.5% "D-60", followed by 350 sacks of class "G" cement with 0.75% "D-65" and 0.5% "D-60", followed by 250 cu.ft. of self-stress cement with 0.5% "D-65" and 0.2% "D-108". Used top and bottom plugs. Displaced with 2,472 cu.ft. of mud. Did not bump plug. Approximately 200 lineal feet left in pipe. Good circulation through out job. Cement in Place at 7:15 a.m., 8/10/79. Removed BOPE. Landed 8 5/8" casing in slips with 265,000#. Cut off 8 5/8" casing. Installed tubing head and tested all seals to 5,000 psi for 1 hour, O.K.

6:00 a.m. Testing CSO.

8-11-79

42nd Day. Finished installing BOPE. Made up drilling assembly (with scraper) and bit #31. Ran in to 3,900'± . Tested pipe rams to 3,000 psi, Hydril to 2,000 psi with water and nitrogen for 20 minutes each. All tests O.K.. Running in hole to clean out.

6:00 a.m. Cleaned out to 7,330'. Pulling out to run CBL.

8-12-79

43rd Day. Ran in hole to 7,220'. Drilled out plugs, float collar and cement to 7,330' with bit #31. Circulated for logs. Pulled out, rigged and ran Welex Cement Bond log from 7,308' to 3,350' (Welex measure). Ran in hole rubbering drill pipe every other joint. Changed over to brine-polymer fluid. Pulling out of hole.

Mud wt. 78#, Vis. 47 sec.

6:00 a.m. W.S.O. holes at 7,204' (Welex measure). 7,217' (Schlumberger measure). Holes broke down at 2,200 psi.

8-13-79

44th Day. Finished pulling out of hole. Welex shot four 1/2" holes at 7,204' - 7,205'. Dowell pressured to 2,200 psi. Holes broke down immediately. Ran in with Baker model "K" cement retainer to 7,239'. Spotted 40 cu.ft. of water in annulus and 60 cu.ft. in drill pipe. Closed pipe rams. Obtained breakdown of 3 cu.ft. per minute at 2,450 psi. Backscuttled out water. Pulled up to 7,209'. Dowell pumped 30 cu.ft. of water ahead of 56 cu.ft. of acid and 30 cu.ft. of water. Spotted 30 cu.ft. of water and 20 cu.ft. of acid in annulus. Pulled up to 7,137' and set retainer. Obtained breakdown of 30 cu.ft. per minute at 1,800 psi. Dowell pumped 50 cu.ft. of water ahead of 115 cu.ft. of class "G" cement with 0.75% "D-65", followed by 50 cu.ft. of water. Displaced with 335 cu.ft. of drilling fluid and stabbed into tool. Squeezed away cement and cleared holes with 20 cu.ft. of water. Cement in Place at 9:30 p.m. Pulling out of hole.

Mud 78#, Vis 46 sec.

6:00 a.m. Pulling out of hole.

8-14-79

45th Day. Finished pulling out of hole. Laid down 24 joints of 4 1/2" 16.60#, and 18 joints of 4 1/2" heavy weight cemented up drill pipe and loaded out same. Unloaded, tallied and picked up 23 joints of 4 1/2" 16.60# drill pipe. Measured in hole with bit #31RR. Tagged cement at 7,129'. Bit plugged. Pulling out wet.

Mud wt. 78#, Vis 48 sec..

6:00 a.m. Going in with bit #31RR to drill out cement and retainer at 7,137'.

8-15-79

46th Day. Finished pulling out of hole with plugged bit. Ran back in cleaned out from 7,080' to 7,113'. Drilled hard cement from 7,113' to 7,137'. Drilled out retainer and hard cement to 7,159'. Circulated clean. With bit at 7,250', Dowell spotted 60 cu.ft. of water, (30 cu.ft. in annulus) Closed rams and got breakdown of 10 cu.ft. per minute at 2,200 psi. Pulled out of hole. Ran Baker model "K" cement retainer on 4 1/2" 16.60# drill pipe to 7,202'. Dowell pumped 56 cu.ft. of acid (12% HCL and 3% HF) and displaced with 540 cu.ft. of drilling fluid. Pulled up to 7,137', closed rams, squeezed away 20 cu.ft. of acid at 8 cu.ft. per minute at 2,000 psi. Set cement retainer and squeezed away 20 cu.ft. at 35 cu.ft. per minute at 2,000 psi. Dowell pumped 50 cu.ft. of water ahead of 115 cu.ft. of class "G" cement blended with 0.75% "D-65" followed by 50 cu.ft. of water, followed by 355 cu.ft. of drilling fluid. Stabbed into model "K" retainer (7,137'). Squeezed away 100 cu.ft. of cement at 10 cu.ft. per minute at 1,000 psi. Locked up at end with 2,500 psi.

Mud 77#, Vis 46 sec.

6:00 a.m. Cement in Place at 12:45 a.m. Going in hole with bit to clean out retainer and cement

Daily Well Report for Mission Adrian #1-B, Aliso Canyon

8-16-79

47th Day. Finished squeeze at 12:45 a.m., reverse circulated 600 cu.ft. of drilling fluid from 7,135'. Chained out of hole. Made up 7 5/8" bit #32 on drilling assembly. Ran in hole to 7,137'. Drilled out retainer, cleaned out cement from 7,157' to 7,204'. Cleaned out to 7,330'. Circulated clean. Pulled up to 7,230'. Dowell pumped 100 cu.ft. of calcium chloride 78# water. Followed by 513 cu.ft. of mud. Closed rams and pressure tested holes at 7,204' - 7,205' with 2,200 psi for 20 minutes, o.k.. Pulled out of hole. Welex shot four 1/2" holes at 7,205' - 7,206'. Dowell pressure tested holes and got a breakdown of 8 cu.ft. per minute at 2,100 psi. Running in hole with Johnston "Hornet" cement retainer.

Mud 76#, Vis 41 sec..

6:00 a.m. Chaining out of hole with Johnston Stabin tool.

8-17-79

48th Day. Finished running in hole with Johnston "Hornet" cement retainer. Set retainer at 7,098'. Dowell pumped 50 cu.ft. of water followed by 57 cu.ft. of class "G" cement blended with 0.75% "D-65 and followed by 50 cu.ft. of water and 409 cu.ft. of drilling fluid. Closed tool. Displaced with 91 cu.ft. of drilling fluid. Starting breakdown 8 cu.ft. per minute at 2,100 psi. Final pressure 2,500 psi and locked. Cement in Place at 2:49 a.m. , 8-17-79. Reverse circulated with 600 cu.ft. of drilling fluid. Ran in with drilling assembly and bit #33. Located cement at 7,082'. Drilled out cement to 7,098' and retainer at 7,098'. Drilled out cement to 7,204'. Ran in to 7,330' and circulated clean. Pulled up to 7,207'. Dowell pumped 60 cu.ft. of calcium chloride water ahead of 509 cu.ft. of drilling fluid. Closed rams and pressure tested holes at 7,205' - 7,206' with 2,200 psi for 20 minutes. Pulled out of hole. Rigging up Welex.

Mud wt. 78.5#, Vis. 47 sec.,

6:00 a.m. New set of four 1/2" holes at 7,206' - 7,207'. Going in hole with Howco "E-Z Drill" retainer.

8-18-79

49th Day. Welex shot four 1/2" holes from 7,206' to 7,207'. Closed blind rams. Dowell obtained breakdown of 3 cu.ft. per minute at 2,100 psi. Ran in with Howco "E-Z Drill" cement retainer to 7,210'. Dowell pumped 50 cu.ft. of water and 550 cu.ft. of drilling fluid. Closed pipe rams and obtained a breakdown of 4 cu.ft. per minute at 2,300 psi. Pulled up to 7,180' and set retainer. Dowell pumped 50 cu.ft. of water ahead of 50 sacks (57 cu.ft.) of class "G" neat cement, followed by 50 cu.ft. of water. Displaced with 442 cu.ft. of drilling fluid, stabbed in and displaced with additional 75 cu. ft. (517 cu.ft. total). Starting rate - 4 cu.ft. per minute at 2,300 psi, final pressure 2,400 psi, locked up. Cement in Place at 12:50 p.m., 8-18-79. Reversed with 600 cu.ft. of drilling fluid. Pulled

8-18-79 continued

out of hole. Ran in with 7 5/8" OMT mill. Milling out Howco "E-Z Drill".

Mud wt. 78#, Vis. 43 sec.

6:00 a.m. Going in hole with bit #34. Mill was not drilling.

8-19-79

50th Day. Milled on retainer. Pulled out and ran with bit #34. Drilled out retainer at 7,180'. Drilled out cement to 7,207'. Ran in to 7,330'. Circulated clean. Pulled up to 7,237'. Dowell displaced 100 cu.ft. of calcium chloride water and 513 cu.ft. of drilling fluid. Closed rams and pressured up to 2,200 psi. Rams leaked. Closed Hydril , pressure tested to 2,200 psi for 20 minutes, ok. Pulled out of hole. Changed 4 1/2" ram rubbers. Welex shot four 1/2" holes from 7,207' - 7,208'. Pressure tested. Holes started taking fluid at 1,800 psi. Final breakdown 10 cu.ft. per minute at 2,000 psi.

Mud wt. 78#, Vis 47 sec.

6:00 a.m. Howco "E-Z Drill" set at 7,180', and preparing to squeeze.

8-20-79

51st Day. Ran in well with Howco "E-Z Drill" retainer and set at 7,184'. Mixed 50 sacks of class "G" cement mixed with latex. Squeezed away 38 cu.ft. at final pressure of 2,300 psi. Reverse circulated well clean. Pulled out of well. Ran in with bit #35 and located top of retainer at 7,184'. Drilled on retainer for 6 hours from 7,184' to 7,185'. Pulled out of well. Ran in with bit #36 to 5,500'.

Mud wt. 78#, Vis. 43 sec..

6:00 a.m. Pulling out of well with bit #36.

8-21-79

52nd Day. Continued running in well with bit #36. Drilled 5 hours on retainer from 7,185' to 7,186'. Pulled out and ran in well with 7 5/8" flat bottom mill. Milled up retainer and cleaned out to 7,330'. Circulated well one hour. Pulled up to 7,207' and equalized 100 cu.ft. of calcium chloride water. Closed pipe rams and pressured up to 2,000 psi which held for 20 minutes.

Mud wt. 78#, Vis. 45 sec..

6:00 a.m. Running in well with Lynes Test Tools for WSO.

Daily Well Report for Miss on Adrian #1-B, Aliso Canyon

8-22-79

53rd Day. Using Welex wireline and jet gun, shot four 1/2" holes from 7,203' to 7,204'. Pressure tested holes to 2,000 psi for 20 minutes. Ran in well with Lynes test tools and set packer at 7,140'. Opened tool at 9:50 a.m., faint blow for 3 minutes and dead balance of one hour test. Pulled and recovered 25' rise of polymer drilling fluid. Test witnessed and approved by DOG. Ran in with bit #37 and drilled out cement from 7,330' to shoe at 7,347'. Drilled to 7,353' and circulated well clean.

Test Pressures:

I.H.	3,705 psi
I.F.	10 psi
F.F.	10 psi
F.H.	3,700 psi

Mud wt. 78#, Vis. 43 sec..

6:00 a.m. Running in with 7 5/8" Diamond core bbl.

8-23-79

54th Day. Ran in well with 7 5/8" Diamond core head and cored from 7,353' to 7,379'. Pulled out and recovered 22'.

Mud wt. 78#, Vis 47 sec..

6:00 a.m. In well with core run #2, circulating preparing to core.

8-24-79

55th Day. Diamond cored 7 5/8" hole from 7,379' to 7,403' for core #2. Recovered 23' of core.

Mud wt. 78#, Vis 49 sec..

6:00 a.m. Coring at 7,412'.

8-25-79

56th Day. Diamond cored 7 5/8" hole from 7,403' to 7,428'. Recovered 23' of core. Diamond cored 7 5/8" hole from 7,428' to 7,439'.

Mud wt. 79#, Vis. 51 sec..

6:00 a.m. Coring at 7,449'.

8-26-79

57th Day. Diamond cored 7 5/8" hole from 7,439' to 7,450' with run #4, and to 7,464' with run #5. Recovered 26' of 3" core.

Mud wt. 79#, Vis 50 sec..

6:00 a.m. 7,469'

8-27-79

58th Day. Diamond cored 7 5/8" hole from 7,464' to 7,475' for core #5 and to 7,485' with run #6

7465 top of 7

Mud wt. 78#, Vis 50 sec., Solids 2%

6:00 a.m. Pulling out of hole with core #6.

8-28-79

59th Day. Diamond cored 7 5/8" hole from 7,484' to 7,485'. (Recovered 2.5 feet of 3" core). Diamond cored 7 5/8" hole from 7,485' to 7,496'.

Mud wt 79.5#, Vis 51 sec., solids 1 1/2%.

6:00 a.m. Running in hole with core #8. Recovered 10' of core #7.

8-29-79

60th Day. Diamond cored 7 5/8" hole from 7,496' to 7,510'. (Recovered 12 1/2 feet of 3" core).

Mud wt. 78#, Vis 50 sec., solids 2%.

6:00 a.m. Drilling with 7 5/8" bit at 7,545'.

8-30-79

61st Day. Drilled 7 5/8" hole from 7,510' to 7,587' with bit #37.

Mud wt. 79#, Vis. 48 sec., Solids 1 1/2%.

6:00 a.m. Diamond coring with 7 5/8" core head at 7,592'.

8-31-79

62nd Day. Diamond cored 7 5/8" hole from 7,587' to 7,604'. (Recovered 13 1/2 feet of 3" core #9). Down 1 hour repairing rotary clutch.

Mud wt. 79#, Vis 47 sec., solids 1%.

6:00 a.m. Diamond coring core #10 with 7 5/8" core head at 7,608'.

9-1-79

63rd Day. Diamond cored 7 5/8 hole from 7,604' to 7,626'. (Recovered 19 1/2 feet of 3" core).

Mud wt. 80#, Vis 48 sec., solids 2%.

6:00 a.m. 7,300' with new diamond core head changing 6" liners to 5 1/2".

9-2-79

64th Day. Diamond cored 7 5/8" hole from 7,626' to 7,656'. (Recovered thirty feet of 3" core). Drilled 7 5/8" hole from 7,656' to 7,684'.

Mud wt. 79#, Vis. 46 sec.

6:00 a.m. Circulating hole clean for logging. T.D. 7,716'. ?

9 -79

65th Day. Drilled 7 5/8" hole from 7,684' to 7,716' with bit #37. Circulated. Pulled up to 8 5/8" casing shoe at 7,347'. Circulated. Ran in to 7,716'. Circulated for logs. Pulled out. Schlumberger ran Dual Induction - SFL, Compensated Neutron - Formation Density logs and recorded from 7,716' to 7,347'. Ran Bore Hole Compensated Sonic log and recorded from 7,716' to 7,000'. Ran Continuous Dipmeter log and recorded from 7,716' to 7,347'. Logging.

Mud wt. 79#, Vis 46 sec., sand Trace, solids 1%

6:00 a.m. Pulling out of hole.

9-4-79

66th Day. Rigged down Schlumberger. Ran in hole with bit #37RR. Tagged bottom (7,716'), no fill. Circulated and pulled out of hole. Laid down 4 1/2" drill collars. Measured and picked up 11 joints of 2 7/8" tubing tail. Ran in to 7,673'. Dowell pumped 70 cu.ft. of water ahead of 100 sacks of class "G" cement with .05% water loss agent. Equalized with 570 cu.ft. of drilling fluid. Cement in Place at 4:53 p.m., 9-4-79. Pulled out of hole. Laid down 2 7/8" tubing. Measured and picked up six 4 1/2" drill collars. Two hours downtime repacking swivel.

Mud wt. 79#, Vis 46 sec.

6:00 a.m. Tagged cement at 7,286'. Cleaning out cement at 7,316'.

9-5-79

67th Day. One hour down time repacking swivel. Ran in hole with 7 5/8" bit # 37RR. Tagged cement at 7,287'. Cleaned out cement to 7,500'. Circulated clean. Pulled out. Laid down and loaded out 4 1/2" drill collars. Made up Tri-State 7 1/2" x 15" under-reamer. Under-reamer would not go through bit guide. Ran bit guide retrieving tool, could not engage guide. Ran Midway 7 1/2" x 7 3/4" spear. Took hold of guide. Pulled 30,000#, would not pull loose.

Mud wt 80#, Vis 46 sec.

6:00 a.m. Waiting on tools.

9-6-79

68th Day. Laid down spear. Hole opener stopped in protector. Attempted to run Baker bridge plug. Ran in with open ended 4 1/2" drill pipe to 6,002' and circulated. Dowell pumped 50 cu.ft. of water ahead of 57 cu.ft. of class "G" cement followed by 6 cu.ft. of water and displaced with 455 cu.ft. of drilling fluid. Cement in Place at 11:45 a.m., 9-6-79. Pulled out of hole. Bit guide came out on last drill pipe rubber. Made up 7 5/8" bit #37RR on casing scraper and three 6" drill collars. Ran in hole and located cement at 5,828'. Drilled out cement to 6,011'. Pulled out of hole. Made up Tri-State 7 1/2" x 15" hole opener. Measuring and picking up heavy weight drill pipe.

Mud wt. 79#, Vis. 45 sec..

6:00 a.m. Opening 7 5/8" hole to 15" at 7,350'. (8 5/8" casing shoe at 7,347').

Daily Well Report for Mission Adrian #1-B, Arroso Canyon

9-7-79

69th Day. Ran in hole with Tri-State hole opener. Opened 7 5/8" hole to 15" from 7,347' to 7,399' with hole opener #1, and to 7,433' with hole opener #2.

Mud wt 79#, Vis 51 sec., solids 2%

6:00 a.m. 7 5/8" hole opened to 15" to 7,436'. Going in hole with #3 hole opener.

9-8-79

70th Day. Opened 7 5/8" hole to 15" from 7,433' to 7,436' with hole opener #2 and to 7,470' with hole opener #3. Ran in with 7 5/8" bit #37RR. Cleaned out fill from 7,470' to 7,500', and drilled out cement to 7,512'. Circulated. Pulling out of hole.

Mud wt 80#, Vis 46 sec.

6:00 a.m. Opening 7 5/8" hole to 15" at 7,476' with hole opener #4.

9-9-79

71st Day. Continued out of hole with 7 5/8" bit. Ran 7 5/8" x 15" hole opener #4. Opened 7 5/8" hole to 15" from 7,470' to 7,477'. Pulled out of hole and ran 7 5/8" x 15" hole opener #5. Reamed 15" hole from 7,475' to 7,477'. Well blew out at 3:25 p.m.. Rigging up to kill well.

6:00 a.m. , 9-10-79. Preparing to kill well.

9-10-79

72nd Day. Rigged up choke manifold and withdrawal line. Dowell commenced pumping 80# mud at 6:40 a.m., at a rate of 3 bbls per min. Starting pressure on drill pipe was 1,200 psi with annulus pressure of 2,780 psi. Drill pipe pressure declined to zero at 570 cu.ft. (102 bbls). Well was dead and BOPE was opened at 11:30 a.m.. Circulated and jarred on stuck pipe. Ran Dia-Log free-point indicator, free point at 7,390'. Ran string shot and backed off at 7,288'. Rigging down Dia-Log.

7347

Mud wt. 80#, Vis 43 sec..

6:00 a.m. Going in hole with Baker bridge plug.

9-11-79

73rd Day. Chained out of hole. Ran in hole with Baker model "C" bridge plug and set same at 6,990'. Pulled out of hole. Replaced Hydril, pipe and blind ram rubbers. Made up and ran in hole with Baker fullbore test packer which was set at 477'. Pressure tested pipe rams with water to 4,000 psi for 20 minutes, o.k.. Pressure testing Hydril.

Mud wt 80#, Vis 46 sec..

6:00 a.m. Hydril test o.k. with water and nitrogen to 3,000 psi for 20 minutes. Testing BOPE.

9-12-79

74th Day. Tested Hydril with water and nitrogen to 3,000 psi for 20 minutes each test, o.k.. Tested pipe rams with nitrogen and would not hold. Welded up washouts in pipe ram seal in body of gate. Tested pipe rams with water to 4,000 psi for 20 minutes, o.k.. Testing with nitrogen.

Mud wt 81#, Vis 47 sec..

6:00 a.m. Pipe rams tested with 4,000 psi of nitrogen for 20 minutes, o.k.. Out of hole slipping and cutting drilling line.

9-13-79

75th Day. Tested pipe rams with nitrogen to 4,000 psi for 20 minutes, o.k.. Pulled out Full-Bore packer from 477'. Attempted test on blind rams with tubing doughnut in head. No Go. Ran in the hole with Baker retrieving tool on 4 1/2" drill pipe. Found and latched on to bridge plug at 5,900'. Ran in to 7,173'. Circulated. Pulled out with Baker model "C" plug. Made up and ran Johnston retrievable bridge plug and set at 60'. Tested blind rams with water and nitrogen to 4,000 psi for 20 minutes both tests, o.k. Retrieved Johnston bridge plug. Made up Midway fishing tools, six 6" drill collars and picking up additional drill collars.

Mud wt. 80#, Vis. 43 sec..

6:00 a.m. Screwed into fish and jarring.

Daily Well Report for Mission Adrian #1-B, Aliso Canyon

9-14-79

76th Day. Finished picking up 6" drill collars. Ran in hole. Circulated. Screwed into fish at 7,288'. Jarred on fish. Unable to pump through fish with rig pump. Rigged up Dowell to establish better, or full circulation. Continued jarring on fish. Dowell pumped 50 bbls (280 cu.ft.) of #2 diesel fuel. Followed by 386 cu.ft. of mud when circulation was lost with 16 bbls of diesel in 7 5/8" x 15" annulus.

Mud wt. 80#, Vis 48 sec.

6:00 a.m. Jarring on fish

9-15-79

77th Day. Displaced diesel fuel with additional 200 cu.ft. of drilling fluid. Let diesel set for one hour. Jarred on fish with 280,000# for 17 hours. Slipped drilling line 40'. Ran free point indicator and string shot. Made one unsuccessful backoff at 7,419'. Pipe backed off up hole. Depth unknown. Screwed back in. Pulling wireline.

Mud wt. 80#, Vis 50 sec.

6:00 a.m. Backed off at 7,385'. Circulating.

9-16-79

78th Day. Dia-Log ran shot #2 which misfired. Ran shot #3 and backed off at 7,385', drill pipe measure, 7,392' wireline measure. Chained and measured out of hole. Laid down fishing tools and fish. Recovered one joint of heavy wall drill pipe, jars, crossover sub, and one 6" drill collar. Made up one 40' joint of 7" washpipe on four 5 3/4" drill collars. Ran in hole slowly. Serviced all tool joints on heavy wall drill pipe going in hole.

Mud wt. 80#, Vis 46 sec.

6:00 a.m. Washing over fish.

9-17-79

79th Day. Continued running in hole with 7" washpipe to shoe of 8 5/8" casing at 7,347'. Circulated for one hour. Washed over fish from 7,385' to 7,439'. Pulled out and laid down washpipe. Made up and ran screw in fishing assembly. Stopped at shoe and circulated for one hour. Screwed into fish at 7,385'. Jarred on fish. Ran Dia-Log free point indicator and string shot. Backed off at 7,422'. Pulled up to 7,217'. Circulating .

Mud wt. 81#, Vis 45 sec.

6:00 a.m. Pulling out of hole.

Daily Well Report for Mission Adrian #1-B, Aliso Canyon

9-18-79

80th Day. Pulled out of hole. Recovered one 6" drill collar. Top of fish now at 7,422'. Ran in with 45' of 7" washpipe. Washed over fish from 7,422' to 7,455'. Pulled out of hole with washpipe. Running in with screw in sub.

Mud wt. 80.5#, Vis. 46 sec..

6:00 a.m. Dia-Log making up Free-point indicator and string shot.

9-19-79

81st Day. Finished running in hole to shoe of 8 5/8" casing shoe and circulated bottoms up. Ran in and screwed into fish at 7,422'. Jarred on fish. Dia-Log ran Free-point and string shot. Attempted to back off at 7,478' with no success. Shot and backed off at 7,449' leaving fish in hole 7,449' - 7,487'. Pulled out of hole. Left one drill collar of fish, screw in sub, bumper sub, jars and two 5 3/4" drill collars of fishing tools. Making up tools to recover lost tools.

Mud wt 80#, Vis. 47 sec..

6:00 a.m. Screwed into lost tools. Running Dia-Log locator to check same.

9-20-79

82nd Day. Ran in hole with screw in sub to shoe of 8 5/8" casing. Circulated bottoms up. Screwed into fish at 7,354'. Pulled out of hole. Laid down one badly damaged 6" drill collar fish. Ran 43' of 3 1/2" drill pipe probe below 4 1/2" drill pipe which stopped at 7,347'. Circulated bottoms up. Attempted to work on down. Wouldn't go. Pulling out of hole.

Mud wt. 80#, Vis 47 sec..

6:00 a.m. Going in hole with new 3 1/2" drill pipe stinger.

9-21-79

83rd Day. Pulled out of hole. Modified 3 1/2" drill pipe stinger. Ran in hole to 7,347'. Circulated bottoms up. Ran in to 7,449' and washed along side of fish to 7,455'. Pulled out of hole. Modifying 3 1/2" 43' stinger.

Mud wt. 80#, Vis 46 sec..

6:00 a.m. Washing along side of fish at 7,460'.

9-22-79

84th Day. Ran in with 40' of 3 1/2" drill pipe stinger. Washed down beside fish from 7,455' to 7,472'. Pulled out. Made up 62' of 3 1/2" drill pipe stinger and ran in hole to 7,345'. Circulating bottoms up.

Mud wt. 80#, Vis 55 sec..

6:00 a.m. Washing down beside fish at 7,480'.

9-23-79

85th Day. Washed down beside fish from 7,472' to 7,484' with 62' of 3 1/2" drill pipe stinger. Pumped down 50 bbls of high viscosity pill. Pulled up to 8 5/8" casing shoe. Set for one half hour. Ran in and tagged bottom at 7,484'. No fill. Pulled out. Ran in well with screw in sub and 10' head collar.

Mud wt 78#, Vis 45 sec..

6:00 a.m. Screwed into fish and jarring

9-24-79

86th Day. Made up screw in sub. Ran in hole. Screwed into fish at 7,449'. Unable to circulate. 7 hours jarring on fish. Ran Dia-Log collar locator. Found fill inside of fish at 7,453'. Cleaned out fill from 7,453' to 7,480'. Ran Dia-Log back off string shot which did not fire.

9-25-79

Jarred on fish 4 hr. Rigged up dialog. Ran a nitro gel shot which was fired at 7479'. Circulated and jarred on fish. Jarred pin of screwin sub out of damaged drill collar box at 7449'. Pulled out of well. Layed down fishing tools. Ran in well with 62' of 2 7/8 tubing stinger on bottom. Equalized cement plug from 7449' up to 7400. Cip at 11:40 P.M.

6:00 A.M. Running in well with 7 1/2" mill

9-26-79

88th Day. Ran in well with 4 1/2" drill pipe and 7 1/2" junk mill. Found top of cement at 7,400'. Loaded out drill collars and fishing tools. Pulled out of well. Made up 5" bent housing Dyna-drill.

6:00 a.m. Running Dyna-drill.

N. McGhee
10/4/79

9-27-79

89th Day. Dyna-drilled 7 5/8" hole from 7,400' to 7,437' with bit #38 and to 7,453' with bit #39.

Mud wt. 80#, Vis. 53 sec., solids 1%

6:00 a.m. Running in hole with drilling assembly.

9-28-79

90th Day. Drilled 7 5/8" hole from 7,453' to 7,478' with bit #39, and to 7,490' with bit #40.

6:00 a.m. 7,509'. Pulling out to log.

9-29-79

91st Day. Circulated well clean and pulled out. Ran Schlumberger Dual Induction SFL log and recorded from 7,509' to 7,342'. Ran drilling assembly. Drilled 7 5/8" hole from 7,509' to 7,512' with bit #41.

6:00 a.m. Running in well with Tri-State 7 1/4" x 15" hole opener.

9-30-79

92nd Day. Ran 7 1/4" x 15" hole opener #6 and opened 7 5/8" hole to 15" from 7,400' to 7,452'. Pulled out.

Mud wt 80#, Vis. 48 sec., solids 1%

6:00 a.m. 15" hole opened to 7,469'. Pulling out with opener #7.

10-1-79

93rd Day. Opened 7 5/8" hole to 15" from 7,452' to 7,469' with hole opener #7 and to 7,476' with hole opener #8.

Mud wt. 80#, Vis 47 sec.

6:00 a.m. Hole opened to 15" to 7,478'. Going in hole with opener #10.

10-2-79

94th Day. Opened 7 5/8" hole to 15" from 7,476' to 7,478' with hole opener #9, to 7,486' with hole opener #10, and to 7,507' with hole opener #11. Pulling out of hole.

Mud wt. 80#, Vis. 48 sec.

6:00 a.m. At shoe with bit and circulating.

10-3-79

95th Day. Finished pulling out of hole. Made up 7 5/8" bit. Circulated for one hour at 8 5/8" casing shoe. Ran in and found fill at 7,483'. Cleaned out to 7,512'. Circulated clean. Pulled out of hole. Ran in with Tri-State hole opener #12. Gauge reamed 15" hole from 7,347' to 7,510'. Circulated clean. Pulled out. Rigged and running Dresser Atlas Caliper log.

Mud wt 81#, Vis. 47 sec..

6:00 a.m. Cleaning pits for gravel pack fluid.

10-4-79

96th Day. Ran Dresser Atlas Caliper log with bore hole volume integrator and recorded from 7,510' to 7,346'. Ran in hole with bit #42 RR to 8 5/8" casing shoe. Circulated. Cleaned out from 7,510' to 7,512'. Pulled back up to shoe. Cleaned mud pits and changed over to 86# gravel pack fluid. Pulled out. Making up 5 1/2" wire wrap liner.

Mud wt 86#, Vis. 53 sec..

6:00 a.m. Running in hole with 5 1/2" liner.

10-5-79

97th Day. Made up and ran 6 joints and 2 pups of 5 1/2" 20# K-55 ST&C 8rd liner. Total length 278.16' including Baker lead seal hanger and port collar. Shoe landed at 7,511'. 10 mesh wire wrap from 7,510' to 7,343'. Blank from 7,343' to 7,280'. Wire wrap from 7,280' to 7,240'. Port collar from 7,240 to 7,233'. Ports at 7,238.55'. Three B&W centralizers installed on bottom, three collars in open hole. 239' of 2 3/8" tubing stinger. B&W flow packing with 20 - 40 gravel

Mud wt. 86#, Vis. 52 sec.

6:00 a.m. Pulling out of hole with gravel packing tool to pick up perforated washer.

10-6-79

98th Day. B&W gravel packed with 228 sacks of 20 - 40 gravel. Back-scuttled and pulled out of hole. Made up and ran washer. (2.60' between cups). Washed liner. Pulled out. Ran in with gravel packing tool. Opened port collar and circulating.

Mud wt. 86#, Vis 52 sec..

6:00 a.m. Rigging up to run Dresser Atlas Photon Log.

Daily Well Report for Mission Adrian #1-B, Aliso Canyon

10-7-79

99th Day. Repacked 5 1/2" liner with 8 cu.ft. of 20 - 40 gravel. Packed off. Backscuttled out 6 cu.ft. for 230 cu.ft. in place. Closed port collar. Tested same with 1,000 psi, o.k. Pulled out. Ran Dresser Atlas Photon log. Log shows 8 lineal foot void immediately below 8 5/8" casing shoe. Ran in with Baker washer and two B&W vibrators. Rewashed and vibrated all of liner. Pulling out.

Mud wt. 86#, Vis 52 sec.

6:00 a.m. Making up gravel packing tools.

10-8-79

100th Day. Finished pulling out. Ran in with gravel packing tools and opened port collar. B&W packed 5 1/2" liner with 34 cu.ft. of 20 - 40 gravel. Backscuttled out 20 cu.ft., 14 cu.ft. in, 243 cu.ft. total in place. Closed and tested port collar with 1,000 psi, o.k. Pulled out of hole. Rigged and ran Dresser Atlas Photon log. Dresser Atlas set Baker 8 5/8" "Retrieva-D" packer at 7,190'.

Mud wt 86#, Vis. 52 sec.

6:00 a.m. Preparing to test packer and seals to 1,500 psi.

10-9-79

101st Day. Ran in hole with Baker two seal and locator sub. Attempted pressure test on packer. Would not test. Built up mud volume. Pulled out of hole. Made up and ran Johnston bridge plug.

Mud wt. 86#, Vis. 62 sec..

6:00 a.m. Attempting to set bridge plug.

10-10-79

102nd Day. Ran in hole with Johnston bridge plug. Unable to set at 7,150'. Pulled out of hole. Ran Baker model "C" bridge plug. Set bridge plug at 7,150'. Howco spotted 8 sacks of sand. Pulled up 3 stands. Waited 2 hours. Ran 3 stands to find top of sand. Bridge plug not set. Reset bridge plug at 7,152'. Howco spotted 8 sacks of sand on bridge plug.

Mud wt. 86#, Vis. 60 sec..

6:00 a.m. Top of sand on bridge plug at 7,132'. Going in hole with Baker fullbore packer.

10-11-79

103rd Day. Waited for sand to fall. Ran in and touched sand at 7,132'. Pulled out of hole. Ran in with Baker fullbore packer. Made 16 pressure tests of 8 5/8" casing. Found leak from 1,597' to 1,605'. Pulled out. Rigged and running McCullough Casing Inspection log.

Mud wt. 86#, Vis. 60 sec..

6:00 a.m. McCullough found leak from 1,594' to 1,596'. Preparing to set bridge plug at 1,700'±

10-12-79

104th Day. Finished running McCullough Casing Inspection log from 7,100' to surface. Found leak from 1,594' to 1,596'. Ran in and set Baker model "C" bridge plug at 1,721'. Howco pumped 8 sacks of silica sand on top of bridge plug. Pulled out of hole. Broke and laid down setting tool. Ran in with open end 4 1/2" drill pipe. Tagged sand at 1,709'. Pulled up to 1,600'. Howco equalized 67 cu.ft of class "G" neat cement, Pulled out of hole. Closed blind rams and squeezed away 62 cu.ft.. Cement in Place at 4:00 p.m., 10-12-79. Final pressure 800 psi. Waiting on cement.

Mud: water

6:00 a.m. Cement cleaned out 1,585' to 1,600'. Pressure test no good Broke at 400 psi. Pulling out with bit and scraper.

10-13-79

105th Day. Ran in hole with 7 5/8" bit #43RR and casing scraper to 1,400'. Changed calcium chloride polymer to water. Drilled cement from 1,585' to 1,600'. Circulated clean. Pressure tested casing. Pumped away at 800 psi. Pulled out. Ran back with open end 4 1/2" drill pipe to 1,601'. Howco equalized 100 cu.ft. of class "G" cement. Pulled out. Closed blind rams. Squeezed away 92 cu.ft. Cement in Place at 8:30 a.m. Waited on cement 12 hours. Ran in with 7 5/8" bit #43RR and 8 5/8" casing scraper. Cleaned out cement frpm 1,580' to 1,601'. Circulated and tested casing. Pumped away at 1,000 psi. Pulled out. Running in with 4 1/2" open end drill pipe.

Mud: water

6:00 a.m. Waiting on cement.

10-14-79

106th Day. Finished running in hole with open end 4 1/2" drill pipe to 1,601'. Howco equalized 100 cu.ft. of class "G" cement blended with 3% calcium chloride. Pulled out. Closed blind rams and squeezed away 80 cu.ft. Cement in Place at 2:30 a.m., 10-14-79. Waited on cement 8 hours. Ran in with 7 5/8" bit and

10-14-79 continued

and casing scraper. Cleaned out cement from 1,500' to 1,608'. Pressure test broke down at 1,200 psi. Pulled out. Ran in with 4 1/2" open ended drill pipe to 1,600'. Howco equalized 100 cu.ft. of class "G" cement blended with 3% calcium chloride. Pulled out. Closed blind rams and squeezed away 85 cu.ft.. Cement in Place at 3:15 p.m., 10-14-79. Waited on cement 8 hours. Running in hole with bit and casing scraper.

Mud: water

6:00 a.m. Waiting on cement.

10-15-79

107th Day. Finished running in hole with 7 5/8" bit and scraper. Cleaned out cement from 1,604' to 1,608'. Stringers to 1,633'. Pulled out of hole. Closed blind rams, pressured up, leak broke down at 1,250 psi. Ran in to 1,619' with 4 1/2" open ended drill pipe. Howco equalized 108 cu.ft. of class "G" cement blended with 3% calcium chloride. Pulled out. Closed blind rams. Attempted to squeeze. Cement in Place at 4:00 a.m.. Final pressure 2,600 psi. Waited on cement for 8 hours. Ran in with bit and scraper. Cleaned out cement from 1,296' to 1,620'. Ran in to 1,683'. Circulated clean. Closed pipe rams. Leak broke down at 1,150 psi. Pulled out of hole. Ran in to 1,619' with 4 1/2" drill pipe. Howco equalized 58 cu.ft. of class "G" neat cement. Pulled out. Closed blind rams. Howco squeezed away 47 cu.ft.. Final pressure 1,200 psi. Cement in Place at 11:00 p.m. Waiting on cement.

Mud: water

6:00 a.m. Waiting on cement.

10-17-79

108th Day. Waited on cement for 11 hours. Ran in hole with 7 5/8" bit #43RR. Cleaned out cement from 1,578' to 1,630'. Circulated clean. Pulled out. Tested casing to 1,250 psi. Would not hold. Ran in and set Howco "E-Z drill" retainer at 1,546'. Howco pumped 62 cu.ft. of Cal seal. Squeezed away 38 cu.ft.. Final pressure 2,600 psi. Cement in Place at 7:45 p.m., 10-16-79. Pulled out. Waited on cement for 2 hours. Running in hole with 7 5/8" bit #44 and scraper.

Mud: water

6:00 a.m. Drilling on retainer at 1,547'.

Daily Well Report for Mission Adrian #1-B, Aliso Canyon

10-17-79

109th Day. Drilled on "E-Z" drill retainer from 1,551' to 1,553' with 7 5/8" bit #44. Pulled out of hole. Ran in with OMT 7 5/8" junk mill but unable to mill. Pulled out. Ran in with 7 5/8" bit #45. Drilled out cement retainer to 1,554'. Drilled out cement to 1,568'.

Mud: water

6:00 a.m. Drilling out cement at 1,600'.

10-18-79

110th Day. Tripped for bit. Drilled out cement from 1,568' to 1,674' with bit #46. Circulated clean. Tested casing. Pumped away at 1,250 psi at 7 cu.ft. per minute. Pulled out of hole. Ran in and set Howco "E-Z" drill cement retainer at 1,548'. Howco squeezed away 53 cu.ft. of class "G" cement mixed with 10% Cal seal. Final pressure 2,600 psi. Cement in Place at 7:00 p.m., 10-18-79. Pulled out. Ran in with bit and located cement at 1,548'. Rigging up to lay down drill pipe.

Mud: water

6:00 a.m. Laying down drill pipe.

10-19-79

111th Day. Laid down drill pipe. Broke Kelly and swivel. Laid down mouse hole and rat hole pipe. Removed BOPE.

6:00 a.m. Installing tree.

10-20-79

112th Day. Installed xmas tree. Cleaned pits. Released rig at 11:00 a.m., 10-20-79.

6:00 a.m. Tearing out rig.

Ex. I - 26

Due to the large file size, this exhibit is an excerpt. The native file of this document is available upon request.

DIVISION OF OIL, GAS, AND GEOTHERMAL RESOURCES

CHECK LIST-RECORDS RECEIVED AND WELL STATUS

Operator: So Cal Gas WELL DESIGNATION "Fernando Fee" 32F

API No. 037-21313 SE 27 T: 3N R.: 16W , SB B. and M.

County: Los Angeles FIELD: Aliso Canyon

Type of Notice: _____ **Date** _____ **Report Number:** _____

RECORDS RECEIVED (ATTACH PAGES IF REQUIRED)

	Date	OK	NEED	Remarks
Well Summary (OG100)				
History (OG103)				
E-Log				
Mud Log				
Dipmeter				
Directional				
Core and/or SWS				
MIT (Noise Temp)	3/14/16	✓		EB. Approval Deferred to Senior

NEW STATUS

DATE: _____

NOTICE OF RECORDS DUE

DATE: _____

DATE: _____

DATE: _____

DATE: _____

WELL STATUS INQUIRY

DATE: _____

DATE: _____

Well Stat

Change Required: _____

Change Done: _____

ABANDONMENTS/REABANDONMENTS/DRILLS/REDRILLS

CalWims Abandonment Form: _____ SURFACE INSPECTION NEEDED _____ COMPLETED _____ *Date and Inspector*

FINAL LETTER NEEDED _____ COMPLETED _____ *(Date)* Calwims DRILL/REDRILL Form _____

ENGINEER'S CHECK LIST

T-REPORT(S) ✓ OPERATOR'S NAME ✓ WELL DESIGNATION ✓ SIGNATURE ✓

Calwims Location _____ Calwims ELEVATION: _____ CONFIDENTIAL RELEASE DATE: _____ PERMIT REQUIREMENTS MET _____

CLERICAL CHECK LIST

LOCATION CHANGE (OG165) _____ ELEVATION CHANGE (OG165) _____ RELEASE OF BOND (OG150) _____

REMARKS

RECORDS SCANNED: _____ (Date)

RECORDS APPROVED: D. O. (Date and Engineer)

Modified OGD2

AOR Datbase _____

PARTMENT OF CONSERVA')N
DIVISION OF OIL, GAS & GEOTHERMAL RESOURCES
1000 S. Hill Rd, Suite 116 Ventura, CA 93003-4458
Phone:(805) 654-4761 Fax:(805) 654-4765

No. T216-0093

REPORT ON OPERATIONS

GAS STORAGE PROJECT
"Sesnon-Frew" - Modelo (Miocene-Eocene)

Amy Kitson
Southern California Gas Company (S4700)
12801 Tampa Ave., SC9382
Northridge, CA 91326

Ventura, California
April 13, 2016

Your operations at well **"Fernando Fee" 32F**, A.P.I. No. **037-21313**, Sec. **27**, T. **03N**, R. **16W**, **SB** B. & M., **Aliso Canyon** field, in **Los Angeles** County, were witnessed on **3/10/2016**, by **Ernest Blevins**, a representative of the supervisor.

The operations were performed for the purpose of **demonstrating that all of the injection fluid is confined to the approved zone.**

DECISION:

DEFERRED PENDING REVIEW BY THE DIVISION'S SAFETY TEAM.

Kenneth A. Harris Jr.
State Oil and Gas Supervisor

By _____
Patricia A. Abel
District Deputy

EB/tkc
OG109

DEPARTMENT OF CONSERVATION
DIVISION OF OIL, GAS & GEOTHERMAL RESOURCES
1000 S. Hill Rd, Suite 116 Ventura, CA 93003-4458
Phone:(805) 654-4761 Fax:(805) 654-4765

No. T216-0092

REPORT ON OPERATIONS

GAS STORAGE PROJECT
"Sesnon-Frew" - Modelo (Miocene-Eocene)

Amy Kitson
Southern California Gas Company (S4700)
12801 Tampa Ave., SC9382
Northridge, CA 91326

Ventura, California
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Kenneth A. Harris Jr.
State Oil and Gas Supervisor

By _____ for
Patricia A. Abel
District Deputy

EB/tkc
OG109

STATE OF CALIFORNIA
DEPARTMENT OF CONSERVATION
DIVISION OF OIL AND GAS

REPORT ON PROPOSED CHANGE OF WELL DESIGNATION

R.D. Phillips, Agent
Southern Calif. Gas Company
810 S. Flower St.
Los Angeles, CA. 90017

Ventura, California
February 23, 1990

Your request, dated February 13, 1990, proposing to change the designation of wells in Sec. 27, T. 3N, R. 16W, SB B.&M., Aliso Canyon field Los Angeles County, District No. 2, has been received.

The proposed change in designation, in accordance with Section 3203, Public Resources Code, is authorized as follows:

From:		To:
IW 56	(037-21354)	"Porter" 32F (037-21354)
IW 57	(037-21355)	"Porter" 32D (037-21355)
IW 58	(037-21321)	"Fernando Fee" 32E (037-21321)
IW 60	(037-21276)	"Porter" 32B (037-21276)
IW 61	(037-21277)	"Porter" 32A (037-21277)
IW 62	(037-21313)	"Fernando Fee" 32F (037-21313)
IW 73	(037-21358)	"Fernando Fee" 32B (037-21358)
IW 75	(037-21356)	"Fernando Fee" 32D (037-21356)
IW 76	(037-21359)	"Fernando Fee" 32C (037-21359)
IW 77	(037-21323)	"Standard Sesnon" 25B (037-21323)
IW 78	(037-21360)	"Porter" 32C (037-21360)
IW 81	(037-21363)	"Porter" 32E (037-21363)

bb

M.G. MEFFERD, State Oil and Gas Supervisor

By Patrick J. Kinnear
Patrick J. Kinnear, Deputy Supervisor

OGD157

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION
DIVISION OF OIL AND GAS

No. P 277-191

REPORT ON PROPOSED OPERATIONS

Santa Paula, California

June 7, 1977

Mr. P. S. Magruder, Jr., Agent
Southern California Gas Co.
P.O. Box 54700 Terminal Annex
Los Angeles, Calif.90054

Your proposal to rework well IW 62 (Name and number), A.P.I. No. 037-21313, Section 27, T. 3N, R. 16W, S.B. B. & M., Aliso Canyon field, Los Angeles County, dated 6-2-77, received 6-6-77, has been examined in conjunction with records filed in this office.

THE PROPOSAL IS APPROVED PROVIDED THAT:

1. Hole fluid of sufficient density shall be used in sufficient quantity to control any subsurface pressures, and a reserve supply of at least one hole volume of this fluid shall be kept on hand at the well site.
2. Blowout prevention equipment, at least of the Division of Oil and Gas Class III rating, shall be installed and maintained in operating condition at all times.
3. Blowout-prevention practice drills shall be conducted at least weekly for each crew, and recorded in the log book.
4. THIS DIVISION SHALL BE NOTIFIED TO WITNESS A PRESSURE TEST OF THE BLOWOUT PREVENTION EQUIPMENT BEFORE COMMENCING DOWNHOLE OPERATIONS.

NOTE: A COPY OF THIS APPROVAL SHALL BE POSTED AT THE WELL SITE PRIOR TO COMMENCING OPERATIONS.

Blanket Bond
PW:h

M. G. MEFFORD (acting)
State Oil and Gas Supervisor

By
Deputy Supervisor

OG111 (11-76-GSR1-30M)

SUBMIT IN DUPLICATE

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION

DIVISION OF OIL AND GAS

DIVISION OF OIL AND GAS
RECEIVED
JUL 3 1986
VENTURA, CALIFORNIA

History of Oil or Gas Well

Operator Southern California Gas Co. Field Aliso Canyon County Los Angeles
Well IW #62, Sec. 27, T 3N, R 16W, SB B. & M.
A.P.I. No. 037-21313 Name J. W. Gourley (Person submitting report) Title Agent (President, Secretary or Agent)
Date June 27, 1986

Signature N.W. Buss 6/27/86
N.W. Buss for J.W. Gourley

Box 3249, Terminal Annex, Los Angeles, CA 90051 (Address)
(213) 689-3925 (Telephone Number)

History must be complete in all detail. Use this form to report all operations during drilling and testing of the well or during redrilling or altering the casing, plugging, or abandonment with the dates thereof. Include such items as hole size, formation test details, amounts of cement used, top and bottom of plugs, perforation details, sidetracked junk, bailing tests and initial production data.

Date	
	MWO No.: 99586 was issued to recover junk and set casing patch
1986	
1-20	Moved CPS Rig M-72 from Well IW #73 to IW #62. Filled well with 142 bbls. of 63#/cu.ft. polymer completion fluid and displaced additional 125 bbls. of fluid from well. Installed back pressure valve in doughnut. Removed xmas tree and installed 9" x 3000 psi Class III BOPE. Pressure tested as follows with water: blind rams 3000 psi for 20 minutes; pipe rams 3000 psi for 20 minutes; Hydril 2300 psi for 20 minutes; choke manifold 3000 psi for 20 minutes. Witnessing of test declined by Mr. Bill Winkle of the D.O.G.
1-21	Using free point and rotational torque indicator, worked Baker seal assembly loose from packer at 7072'. Circulated well. Pulled out of well, laying down production equipment (one 2-7/8" Camco gas lift mandrel, one 2-7/8" Camco annular flow safety system, one 2-7/8" Camco heavy wall tube, one Baker anchor seal assembly with 4 seals and one 5' production tube). Made up 8-5/8" bit and casing scraper on 2-7/8" tubing and ran in well to packer.
1-22	Pulled out of well with bit and scraper. Made up Baker locator seals on 2-7/8" tubing. Ran seals to packer at 7072'. Pressure tested packer at 1500 psi for 15 minutes. Pulled out of well, changing 2-7/8" tubing collars on bottom 5208' of tubing. Baker sealed the threads.
1-23	Made up Baker 8-5/8" x 5-1/2" 17# casing patch on 2-7/8" tubing. Using wireline, oriented Baker patch from 1978'-2023', across stage collar at 2001'. Set Baker casing patch. Pulled out of well, laying down setting tools. Secured well.

1986

1-24 Made up one 2-7/8" x 5' Baker production tube on one 2-7/8" Baker anchor seal assembly with 2 seal units, one joint of 2-7/8" tubing, one BST PSI "DU" 2-7/8" x 1.0" gas lift mandrel; hydrotested tubing in well to 7073'. Spaced out and attached to Retrieva-D packer and landed with 10,000# on latch when doughnut was in place. Installed back pressure valve in doughnut. Removed BOPE and installed tree. Pressure tested tree and doughnut at 5000 psi. Displaced polymer completion fluid from well with 430 bbls. of 3% KCl water. Released rig at 10:00 p.m. on 1-24-86.

Ex. I - 27

Well Name: Standard Sesnon 25A

Field: Aliso Canyon

Status: Injection/Withdrawal

Flow Regime: Large Tubing Flow

Elevation: 2927' G.L.
15' K.B.

Surf. Loc.: 814' South and 5373' West of Station 84, Sec. 28, T3N, R16W.

Btm.Hole Loc: 965' North & 6.32' East of surface @ 8805' TVD.

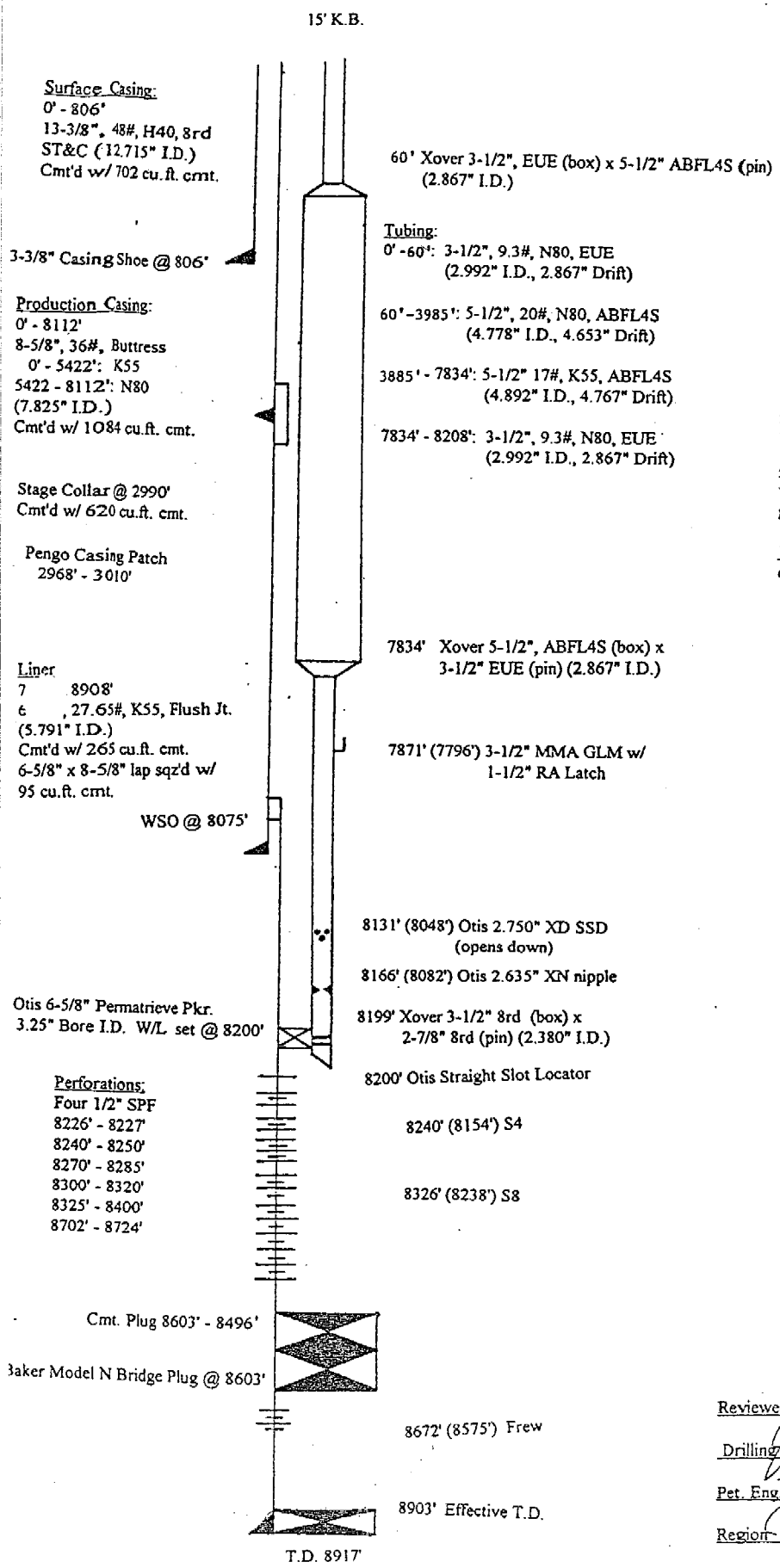
11/2/72-12/7/72: Well spudded and completed.

7/9/76-7/22/76: Cleaned out to 8603', permanent bridge plug moved up hole, plugged back to 8496' and reperfed with jets, tbg. w/ SSSV.

10/19/81-10/29/81: Installed casing patch across leaking collar from 2968'-3010'.

4/20/83-4/27/83: Installed 5-1/2" large tubing with annulus inhibited with fluid to prevent gas leakage through casing patch.

12/4/93-12/22/93: Replace 5-1/2" large tubing due to externally aligned pitting.



Volumes	Bbls	Cu.Ft.
Tubing	177	991
Annulus	247	1386
Csg./Liner	4	20
Total	424	2397

Reviewed	By	Date
Drilling	[signature]	2/3/94
Pet. Eng.	[signature]	2/3/94
Region	[signature]	2/2/94

AC_BLD_0001172

Ex. I - 28

Due to the large file size, this exhibit is an excerpt. The native file of this document is available upon request.

State of California • Natural Resources Agency
Department of Conservation
Division of Oil, Gas, and Geothermal Resources
801 K Street • MS 18-05
Sacramento, CA 95814
(916) 445-9686 • FAX (916) 319-9533

Edmund G. Brown Jr., *Governor*
Kenneth A. Harris Jr., *State Oil and Gas Supervisor*

January 3, 2017

SENT VIA EMAIL

Mr. Rodger Schwecke
Vice President
Transmission and Storage
Southern California Gas Company
RSchwecke@semprautilities.com

FINDING THAT WELL STANDARD SESNON 25A (API NO. 03721322) HAS PASSED THE FIRST BATTERY OF TESTS AND WAS TAKEN OUT OF SERVICE AND ISOLATED FROM THE UNDERGROUND GAS STORAGE RESERVOIR

Dear Mr. Schwecke:

I am writing regarding the safety review results of one of the 114 wells at the Aliso Canyon gas storage facility (Facility). Each of the wells are subject to the comprehensive safety review that State Oil and Gas Supervisor Order 1109 and SB 380[1] require to be completed before the Division of Oil, Gas, and Geothermal Resources (Division) may authorize resumption of injection operations at the Facility. Order 1109 describes two batteries of well tests. To complete the review, each well must (1) pass both batteries of tests, (2) pass the first battery of tests and be taken out of service and isolated from the underground gas storage reservoir, or (3) be properly plugged and abandoned.

The first battery of tests assesses the casing using temperature and noise logs to ensure that there is no migration of fluids near the wellbore. If a well passes those tests, it may (1) undergo the second battery of tests for potential approval to use for injection if and when injections may resume, or (2) be taken out of service and isolated from the underground gas storage reservoir as specified in Steps 4b through 7b of the Safety Review Testing Regime of Order 1109 (Testing Regime). The Division posts the current status and testing results for each of the 114 wells on its website at http://www.conservation.ca.gov/dog/AlisoCanyon/Pages/Well-Detail.aspx.

After receiving and evaluating all test results and other data concerning the well, I find for purposes of Order 1109 and SB 380, that well Standard Sesnon 25A (API No. 03721322) has completed the first battery of the Testing Regime and was taken out of service and, on September 29, 2016, the well was isolated from the underground gas storage reservoir as specified in Step 6b of the Testing Regime. Monitoring and testing of the well must continue as required by Order 1109 and any applicable law. If the well does not pass the second battery of tests within one year of being isolated from the reservoir, then the well must be plugged and abandoned in accordance with Public Resources Code section 3208.

Sincerely,

Kenneth A. Harris Jr.,
State Oil and Gas Supervisor

[1] Senate Bill 380 (Pavley, Chapter 14, Statutes of 2016) codified in part at Public Resources Code section 3217.

NATURAL RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION
DIVISION OF OIL, GAS, AND GEOTHERMAL RESOURCES

Rec'd 07-28-16 DOGGR Ventura.

FOR DIVISION USE ONLY			
	Forms		
Bond	~~OGD114~~	OG121	
	CAL WIMS	115	

P2116-0156

NOTICE OF INTENTION TO REWORK / REDRILL WELL

Detailed instructions can be found at: www.conservation.ca.gov/dog/

In compliance with Section 3203, Division 3, Public Resources Code, notice is hereby given that it is our intention to rework ☒ / redrill ☐ (Check one) well Standard Sesnon 25A, API No. 037-21322.

Sec. 28, T. 3N, R. 16W, SB B.&M., Aliso Canyon Field, Los Angeles County.

The complete casing record of the well (present hole), including plugs and perforations, is as follows: (Attach wellbore schematics diagram also.)
See attached wellbore schematic and completed work summary

The total depth is: 8917 feet. The effective depth is: 8903 feet.

Present completion zone(s): Sesnon (Name). Anticipated completion zone(s): Same (Name).

Present zone pressure: storage psi. Anticipated/existing new zone pressure: storage psi.

Is this a critical well as defined in the California Code of Regulations, Title 14, Section 1720(a) (see next page)? Yes☐ No☒

For redrilling or deepening only, is a California Environmental Quality Act (CEQA) document required by a local agency? Yes☐ No☐ If yes, see next page.

The proposed work is as follows: (A complete program is preferred and may be attached.)
7b - MIRU pump, with casing valve open, pressure-up on tubing to 1000 psi for 1 hour.
Switch pump to casing and, with tubing valve open, pressure-up on casing to 500 psi for 1 hour.
Note: Casing test pressure reduced to 500 psi due to casing patch installed across stage collar at 2990' in 8-5/8" casing.

If well is to be redrilled or deepened, show proposed coordinates (from surface location) and true vertical depth at total depth: _____ feet _____ (Direction) and _____ feet _____ (Direction) Estimated true vertical depth: _____

Will the Field and/or Area change? Yes☐ No☒ If yes, specify New Field: _____ New Area: _____

The Division must be notified immediately of changes to the proposed operations. Failure to provide a true and accurate representation of the well and proposed operations may cause rescission of the permit.

Name of Operator			
Southern California Gas Company			
Address: P.O. Box 2300		City/State: Chatsworth, CA	Zip Code: 91313-2300
Name of Person Filing Notice: A.J. Alshammasi	Telephone Number: (818) 700-3887	Signature	Date: 07/27/2016
Individual to contact for technical questions: Jacob Zachry	Telephone Number: (805) 256-5401	E-Mail Address: jzachry@semprautilties.com	

This notice and an indemnity or cash bond must be filed, and approval given, before the workover begins. (See the reverse side for bonding information.) If operations have not commenced within one year of the Division's receipt of the notice, this notice will be considered cancelled.

OG107 (1/09)

60

Rec'd 07-28-16 DOGGR Ventura.

Completed Work Summary -SS25A		
Step	Work Completed	Date
4b	Good bond across MP per Acoustic Cement Bond Log dated 12/14/1972	12/14/1972
5b	6-5/8" hydraulic packer set in good cement at 8181'	10/27/2010
5b	Tubing plug set in No-Go nipple at 8144'	11/23/2015
6b	Tubing and casing filled with 3% KCl independently (sliding sleeve will not open)	5/22/2016

Rec'd 07-28-16 DOGGR Ventura.

Well
Standard Sesnon 25A

API #: 04-037-21322-00
Sec 28, T03N, R16W

Operator: So. California Gas Co.

Lease: Standard Sesnon
Field: Aliso Canyon
Status: Active Gas Storage
BFW:
USDW:

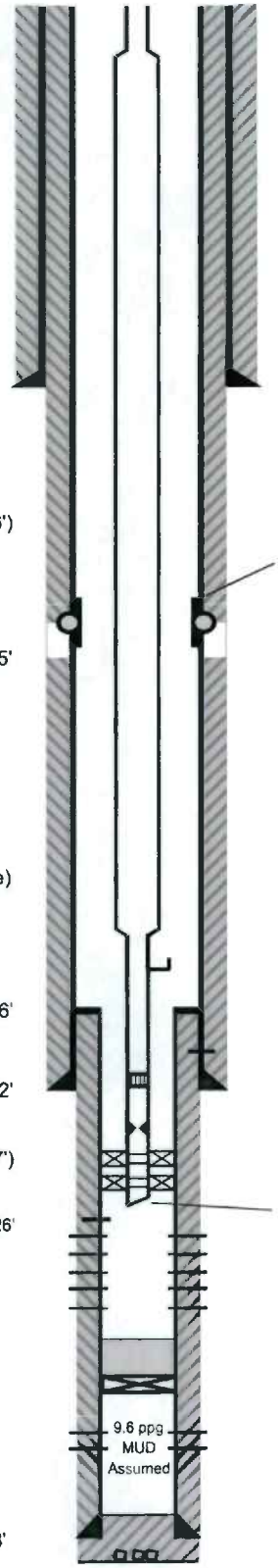
Ground Elevation: 2927' asl
Datum to Ground: 15' KB

Spud Date: 11/2/1972
Completion Date: 12/23/1972

Junk: Lost Cones off bit & one blade off stabilizer @ 8917'

Notes
*No circulation while CMT'ing 13-3/8" CSG

Top of Zone Markers	md	(tvd)
MPupth	4163'	(4159')
A1	4521'	(4517')
UP	5768'	(5742')
LP	6188'	(6151')
UDA1	6506'	(6461')
MDA	7183'	(7122')
LDA	7410'	(7344')
MP	7945'	(7868')
S1	8134'	(8053')
S4	8240'	(8156')
S8	8326'	(8240')
FREW	8674'	(8579')



13-3/8" TOC Surface
8-5/8" TOC (2nd Stage) Surface

17-1/2" Hole (to 808')

Surface Casing
13-3/8", 48#, H-40
0' - 806'

CMT'D w/ 352 CF*
+ CMT'D 5X's w/ a total of
225 SKS CMT + 10 SKS LCM
thru 1" pipe @ 80' BGL Top Job,
Good CMT Returns to Surface 806'

11" Hole (808' - 8116')

8-5/8" ETOC (1st Stage) 3455'

Production Casing
8-5/8"
0' - 5422' 36#, K-55
5422' - 8112' 36#, N-80

CMT'D w/ 1084 CF + 100 SKS (1st Stage)
+ 909 CF thru Stage Collar @ 2990'
(2nd Stage), Good CMT Returns to
Surface (2nd Stage)

6-5/8" TOL & TOC 7926'

8112'

7-5/8" Hole (8116' - 8917')

Four (4) 1/2" Holes (12/14/1972) Co. WSO 8226'

Liner
6-5/8", 27.65#, K-55
7926' - 8908'

CMT'D w/ 265 CF + 95 SKS CMT
SQZ'D Away thru TOL

PBTD 8903'

8908'

TD 8917'
TVD (8816')
Directionally Drilled: Yes (TD is 4' W, 963' N of Surf)

3-1/2" x 5-1/2" X-Over

Tubing

3-1/2"	0' - 50'	9.3#, N-80
5-1/2"	50' - 7845'	20#, N-80
3-1/2"	7845' - 8184'	9.3#, N-80
2-7/8"	8184' - ~8204'	6.4#, N-80

2970' - 3110' Homco CSG Patch
(9/8/2010, patch did not pressure test)
2990' Stage Collar

7845' 5-1/2" x 3-1/2" X-Over

7880' GLMA w/ 1.5"

7926' 6-5/8" x 8-5/8" Lap WSO (12/13/1972)

8075' Four (4) 1/2" Holes (11/29/1972) WSO
8109' Sliding Sleeve

8144' XN' No-Go Nipple
8181' HES G-77 PCKR
8200' - 8204' Otis Permatrieve PCKR
~8204' Mule Shoe

6-5/8" Perfs: 8240' - 8250', 8270' - 8280', 8282' - 8285', 8300' - 8308', 8312' - 8320', 8325' - 8355', 8364' - 8400' Four (4) 1/2" HPF (7/15/1976)
8280' - 8282', 8308' - 8312', 8355' - 8364', 8702' - 8724' Four (4) 1/2" HPF (12/1972)
8240' - 8250', 8270' - 8285', 8300' - 8320', 8325' - 8400' Two (2) ~0.28" SPF (2/1/2006)
8496' - 8603' CMT Plug (30 SKS, 7/14/1976))

8603' Baker Model N Bridge Plug (orig. set @ 8686' on 12/19/1972, Found @ current location on 7/13/1976)

8917' Top of Junk

Prepared by: CAM (7/25/2016)

InterAct

Rec'd 07-28-16 DOGGR Ventura.

Casing Pressure Test Safety Check (500 psi)

Well	Packer Depth MD/TVD	Casing Size/Grade/Weight	Depth MD	Burst PSI	85% of Burst PSI	Pressure at Depth w/500 psi Surface Pressure	Press < 85% of Burst
Standard Sesnon 25A	8181	8-5/8", 36#, K-55	5422	4460	3791	2897	Yes
		8-5/8", 36#, N-80	7926	6490	5517	4003	Yes
		6-5/8", 28#, K-55	8181	6170	5245	4116	Yes

GO INTERNATIONAL

Cement Bond Log with Sonic Spectrum

FILING NO.

COMPANY PACIFIC LIGHTING SERVICES COMPANY

WELL IW #69 SS 25A

FIELD ALISO CANYON

STATE CALIFORNIA COUNTY LOS ANGELES

LOCATION: FROM STATION 84, 814' SOUTH AND 5373' WEST

SEC 28 TWP 3N RGE 16W

OTHER SERVICES: N/L J/P

PERMANENT DATUM: MAT ELEV. 2927

LOG MEASURED FROM K.B. 15 FT. ABOVE PERM. DATUM

DRILLING MEASURED FROM K.B.

ELEV.: K.B. 2942 D.F. G.L. 2927

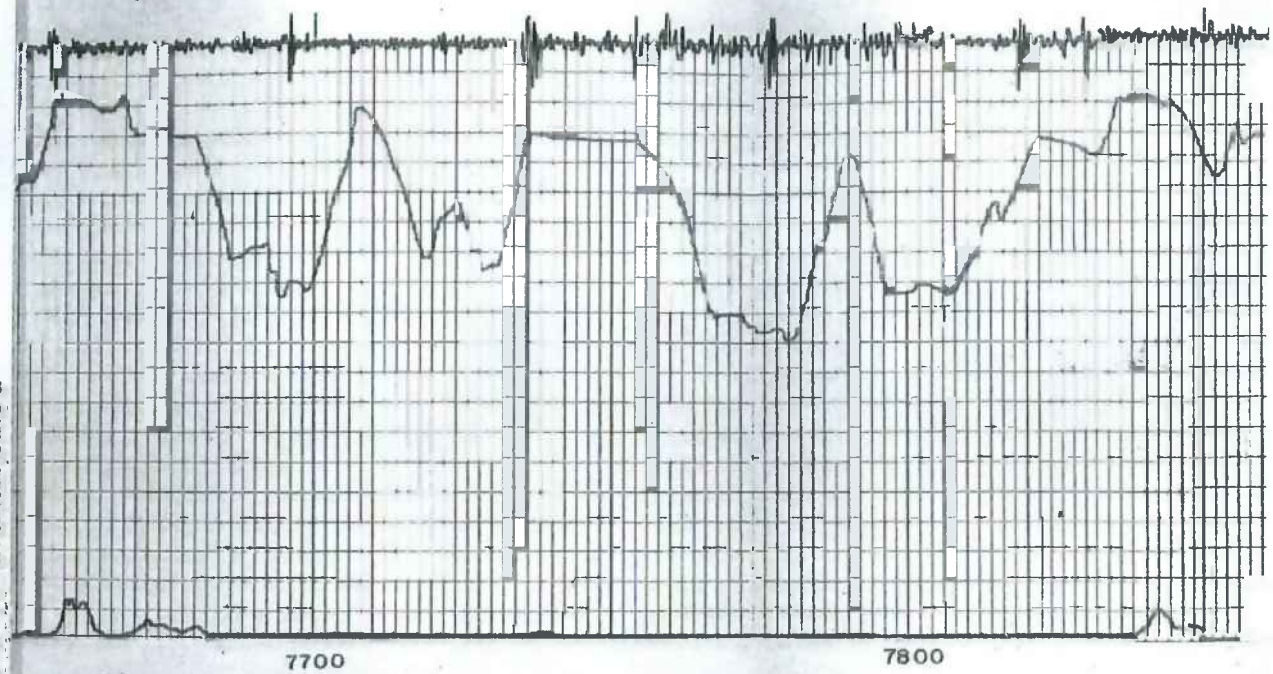
DATE	12-14-72
RUN NO.	ONE
TYPE LOG	CBL/SS
DEPTH-DRILLER	8903
DEPTH-LOGGER	8902
BOTTOM LOGGED INTERVAL	8901
TOP LOGGED INTERVAL	SURF.
TYPE FLUID IN HOLE	MUD
SALINITY, PPM CL	
DENSITY	
LEVEL	FULL
MAX. REC. TEMP. DEG. F	N.R.
OPERATING RIG TIME	6 HRS.
RECORDED BY	FOSTER
WITNESSED BY	MR. GEDDES MR. ALSON

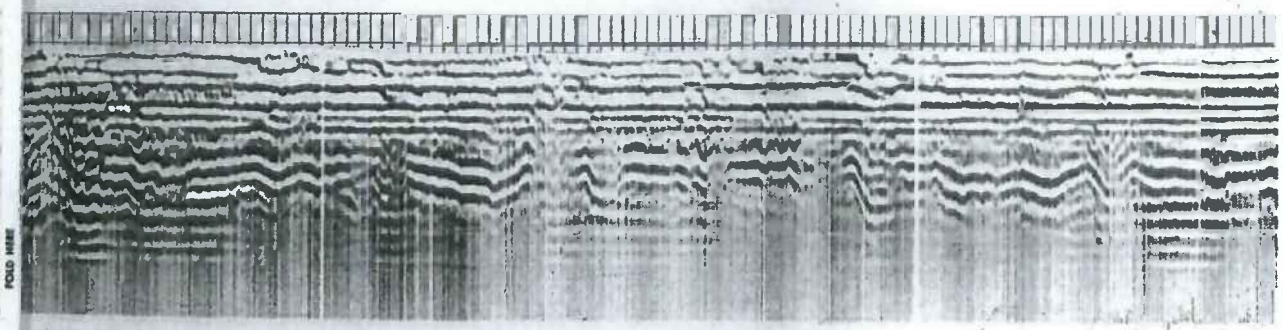
Rec'd 07-28-16 DOGGR Ventura.

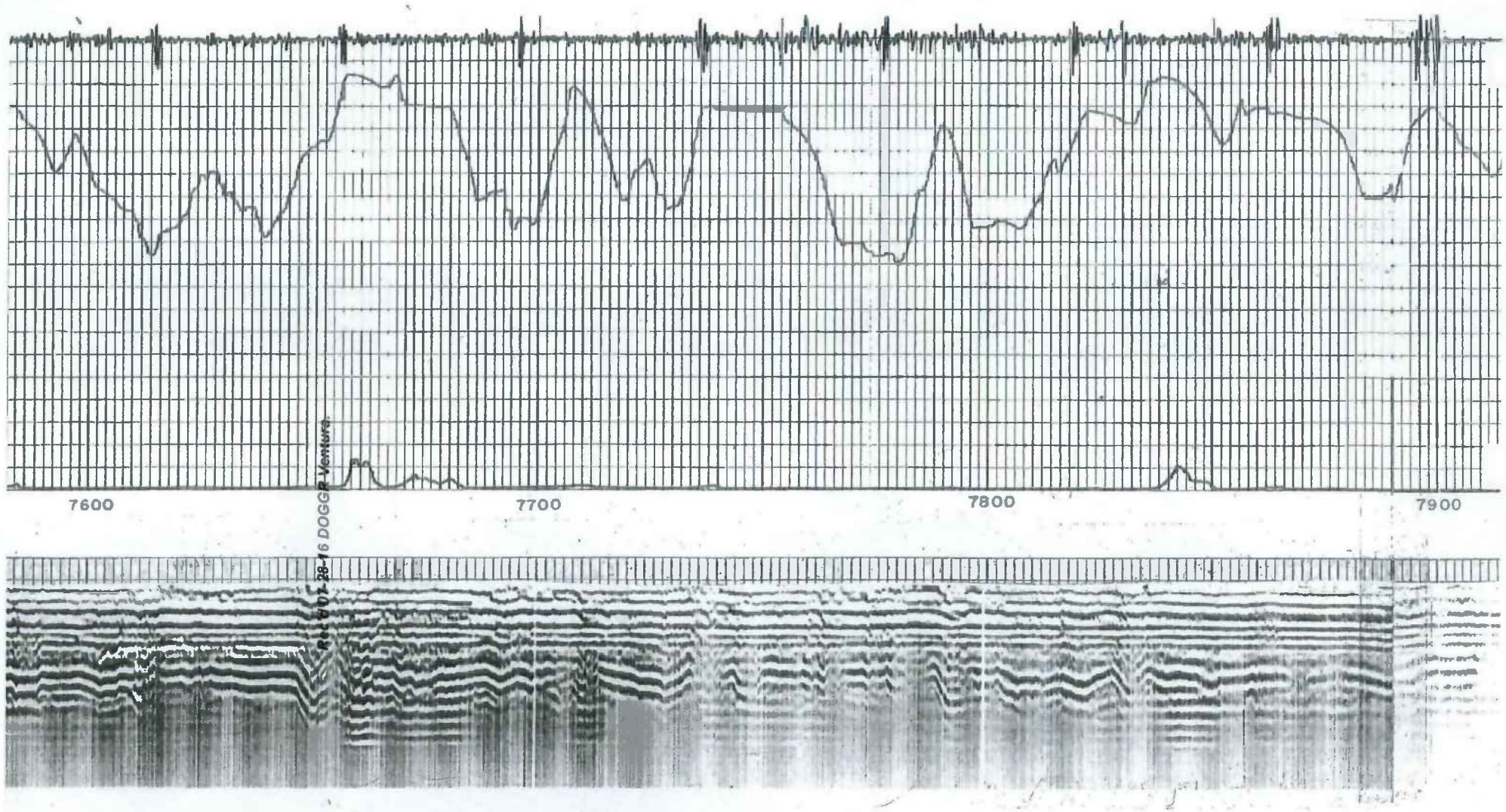
RUN NO.	BORE-HOLE RECORD BIT	FROM	TO	CASING RECORD SIZE	WGT.	FROM	TO
1				13-3/8		SURF.	806
2	11	806	8116	8-5/8	36	SURF.	8112
3	7-5/8	8116	8910	6-5/8	28	8926	8908

THIS HEADING AND LOG CONFORMS TO API RP 33

FOLD HERE







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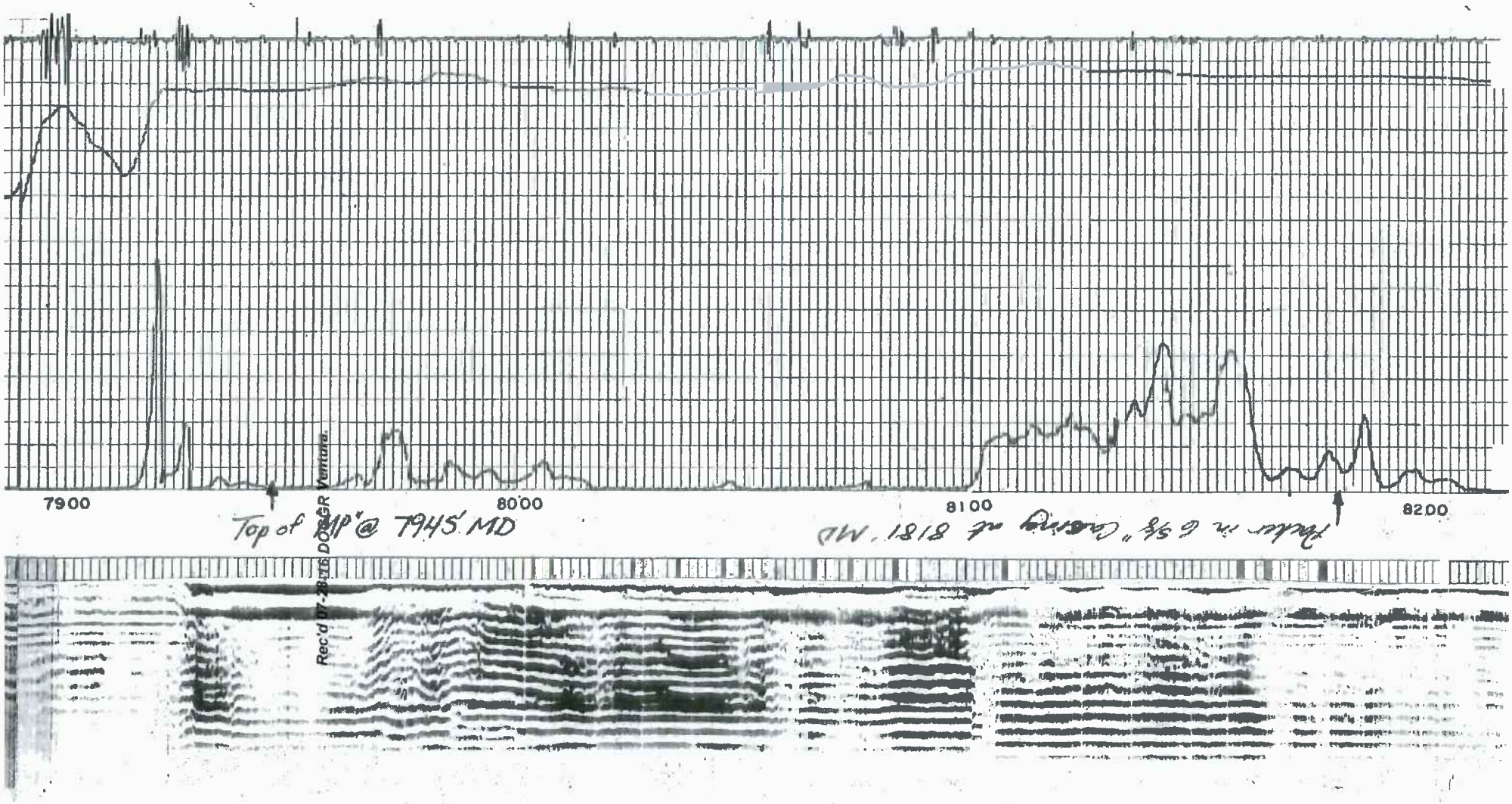
7900
8000
8100
8200
Top of MP @ 7945' MD
Rec'd 07-28-16 DOGGR Ventura.

DIVISION OF OIL, GAS, AND GEOTHERMAL RESOURCES

CHECK LIST-RECORDS RECEIVED AND WELL STATUS

OPERATOR Southern Calif. Gas Co. WELL DESIGNATION: "Standard Sesnon" 25A

API No. 03721322 SEC 28 , T. 3N , R. 16W , SB B. and M.

COUNTY: Los Angeles FIELD Aliso Canyon

Type of Notice: Rework Date: 7/2/2010 Report Number: P210-154

RECORDS RECEIVED (ATTACH PAGES IF REQUIRED)

	Date	OK	NEED	Remarks
Well Summary (OG100)	12/27/10			
History (OG103)				
E-Log				
Mud Log				
Dipmeter				
Directional				
Core and/or SWS				

NEW STATUS

DATE: 8/10

NOTICE OF RECORDS DUE

DATE: 11/5/10

DATE:

DATE:

DATE:

WELL STATUS INQUIRY

DATE:

DATE:

Well Stat

Change Required: NO

Change Done:

ABANDONMENTS/REABANDONMENTS/DRILLS/REDRILLS

ABANDONMENT DATABASE : SURFACE INSPECTION NEEDED COMPLETED
Date and Inspector

FINAL LETTER NEEDED COMPLETED (Date) DRILL/REDRILL DATABASE

ENGINEER'S CHECK LIST

T-REPORT(S) ✓ OPERATOR'S NAME ✓ WELL DESIGNATION ✓ SIGNATURE ✓

LOCATION ELEVATION: CONFIDENTIAL RELEASE DATE: PERMIT REQUIREMENTS MET ✓

CLERICAL CHECK LIST

LOCATION CHANGE (OG165) ELEVATION CHANGE (OG165) RELEASE OF BOND (OG150)

REMARKS

RECORDS SCANNED: 12/27/10 (Date)

RECORDS APPROVED: 12/27/10 (Date and Engineer)

Modified OGD2

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RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION
DIVISION OF OIL, GAS, AND GEOTHERMAL RESOURCES

HISTORY OF OIL OR GAS WELL

Operator: Southern California Gas Company
Well: Standard Sesnon 25 A
A.P.I. No. 03721322

Field: Aliso Canyon
County: Los Angeles
Surface Location: Sec 28 3N 16W S.B.B.M.
Title: Senior Storage Field...

Dan Neville
(President, Secretary, or Agent)

Date: 12/27/2010

DEC 27 2010

Signature:
(Person Submitting Report)

Address: PO Box 2300, SC9365, Chatsworth, CA, 91313-2300

Telephone Number: 818-700-3810

History must be complete in all detail. Use this form to report all operations during drilling and testing of the well or during redrilling or altering the casing, plugging, or abandonment, with the dates thereof. Include such items as hole size, formation test details, amounts of cement used, top and bottom of plugs, perforation details, sidetracked junk, bailing tests, and initial production data.

Start Date	Ops. DOGGR Rpt
8/3/2010	Opened well (2300 psi on tubing). Rigged up wire line. Pulled PXN plug at 8168'. Rigged down wire line. Rigged up for well kill. Pumped 50 bbls hi-vis polymer pill and displaced with 179 bbls 9.5 ppg KCL. Killed well per schedule with 430 bbl KCL water. Installed back pressure plug. Nippled up Class III BOP. Nippled up choke manifold. Rigged up accumulater and function tested BOP.
8/4/2010	Opened well (0 psi tubing and casing.) Filled well with 22 bbls. Rigged up testers. Tested blind rams to 5000 psi for twenty minutes (3" control valves leaking). Continued testing BOP. Tested pipe rams to 5000 psi and Hydril to 3500 psi for twenty minutes. Repaired control vavles. Tested to 5000 psi (pipe ram shaft seals leaking.) Shut down for repairs.
8/5/2010	Repaired pipe ram shaft packing. Tested to 500 psi (ram packing leaking would not test). Waited on equipment. Replaced pipe ram door. Replaced 3-1/8" control valve. Tested pipe rams to 300 psi low and 5000 psi high for twenty minutes. Tested 3 -1/8" control to 300 psi low and 5000 psi high.
8/6/2010	Tested pipe rams and 3" control valve to 5000 psi for twenty minutes (W. Beil DOGGR witnessed and approved BOP test). Filled well with 10 bbls. Backed out hold down studs. Unlanded tubing at 170,000#. Worked stuck tubing to 190,000#. Worked up 4.5' (Clutches out of adjustment, shut down for repairs).
8/9/2010	Filled well with 31 bbls. Rigged up Tiger wire line, made up free point tools and ran in well. Free at 2800', free at 3400', free at 7800', and free at 8150'. Pulled out of well and made up chemical cutter. Ran in well to 8150' and cut 3-1/2" tubing. Rigged out wire line unit. Rigged up casing tongs. Pulled out of well laying down 5-1/2" tubing to kill sting at 4000'.
8/10/2010	Filled well with 4 bbls. Pulled out of well and layed down 5-1/2" and 3-1/2 " tubing. Rigged out casing tongs. Changed pipe rams. Rigged up tubing equipment. Measured and picked up 3-1/2" work string to kill string at 3202'.
8/11/2010	Filled well with 7 bbls. Measured and picked up 3-1/2" tubing to 8150'. Engaged fish and pulled seals loose. Pulled out of well to 6000'.
8/12/2010	Filled well with 5 bbls. Pulled out of well laying down fish tools (recovered seals , no/go, one joint and 13' cut off of 3-1/2" tubing). Made up 7" spear, bumper sub, jars,(2) 4-3/4" drill collars and intensifer. Ran in well to 2968', engaged top cone of patch and jarred loose. Pulled out of well and layed down fish (recovered top cone). Made up fish tools and ran in well to 2969'. Engaged fish and jarred loose. Pulled to 2800'.
8/13/2010	Filled well with 9 bbls. Pulled out of well with casing patch. Layed down casing patch (recovered 41' casing patch, left 1' and bottom cone in well). Ran in well with kill string to 3000'.
8/16/2010	Filled well with 19 bbls. Pulled out of well with kill string. Made up 7" spear assembly ,bumper sub, jars, (2) 4-3/4" drill collars. Ran in well to fish at 3010'. Engaged fish and jarred loose. Pulled out of well (recovered 1' and bottom cone.) Layed down fishing tools. Made up 8-5/8" casing scraper with bumper sub and ran in well to 7640'.
8/17/2010	Filled well with 7 bbls. Ran in well to liner top at 7926'. Pulled out of well and layed down 8-5/8" scraper. Made up 6-5/8" casing scraper and ran in well to packer at 8200'. Pulled out of well to kill string at 3400'.
8/18/2010	Filled well with 9 bbls. Pulled out of well with kill string and laid down casing scraper. Nippled up shooting flange. Rigged up Schlumberger wireline and ran USIT log from 8200' to surface. Rigged down loggers and nippled down shooting flange. Ran in well with kill string to 3300'.
8/19/2010	Filled well with 5 bbls. Pulled out of well with kill string. Made up mill and (2) 4-3/4" drill collars and ran in well to 2980'. Attempted to work with tongs. (Shut down and wait for power swivel).
8/20/2010	Filled well with 9 bbls. Picked up power swivel and ran in well to 2990'. Cleaned up stage collar with 7-5/8" string mill. Pulled out of well and laid down mill and drill collars. Made up 6-5/8" bridge plug and ran in well to 7700'.
8/23/2010	Filled well with 13 bbls. Ran in well with bridge plug to 8127'. Set BP and tested to 500 psi for twenty minutes. Dumped 2 cu ft sand on BP. Pulled out of well (down 2 hours for rig repairs). Made up 8-5/8" lok-set bridge plug and ran in well to 2812'. Set BP and tested annulus to 1700 psi for twenty minutes (good). Ran in well to 3188' and set BP. Tested annulus to 1600 psi (bled to 0 psi in 13 minutes). Tested below packer to 500 psi for twenty minutes (good). Released BP.

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RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION
DIVISION OF OIL, GAS, AND GEOTHERMAL RESOURCES

HISTORY OF OIL OR GAS WELL

Operator: Southern California Gas Company
Field: Aliso Canyon
County: Los Angeles
Well: Standard Sesnon 25 A
Surface Location: Sec 28 3N 16W S.B.B.M.
A.P.I. No. 03721322
Dan Neville
Title: Senior Storage Field...
(President, Secretary, or Agent)

Date: 12/27/2010
Signature:
(Person Submitting Report)

Address: PO Box 2300, SC9365, Chatsworth, CA, 91313-2300
Telephone Number: 818-700-3810

History must be complete in all detail. Use this form to report all operations during drilling and testing of the well or during redrilling or altering the casing, plugging, or abandonment, with the dates thereof. Include such items as hole size, formation test details, amounts of cement used, top and bottom of plugs, perforation details, sidetracked junk, bailing tests, and initial production data.

Start Date	Ops. DOGGR Rpt
8/24/2010	Fill well with 2 bbls. Set packer at 3218' and tested below packer to 500 psi for twenty minutes (good). Released packer and ran in well to 5410'. Set packer and tested below packer to 500 psi for twenty minutes (good). Released packer ran in well to 7900'. Set packer and tested to 500 psi for twenty minutes (all tests good). Released packer and pulled to 3200' kill string.
8/26/2010	Filled well with 7 bbls. Ran in well to 3000' and set packer. Tested annulus to 1600' psi (bled down to 0 in 14 minutes). Released packer and moved to 2980'. Tested annulus to 1600 psi for twenty minutes (good). Pulled out of well and laid down packer. Ran in well with 3100' kill string.
8/27/2010	Filled well with 2 bbls. Pulled out of well with kill string. Made up 8-5/8" bridge plug and packer assembly. Ran in well. (change in orders.) Pulled out of well and laid down packer and BP. Made up retrieving tool and ran in well to 8110'. Nippled up PGSR and circulated out sand. Released 6-5/8" bridge plug. Nippled down PGSR and pulled out of well to 6000'.
8/30/2010	Filled well with 40 bbls. Casing started flowing. Circulated well with 80 bbls. Pulled out of well and laid down 6-5/8" bridge plug. Made up 8-5/8" bridge plug and packer. Ran in well to 6000' and set and released from BP. Pulled to 5000' and set packer. Tested from 5000' to 6000' at 1000 psi for twenty minutes (good). Released packer and ran in well to 6000'. Released BP, pulled to 5000' and set BP. Pulled to 4000' and set packer. Tested from 5000' to 4000' to 1430 psi for twenty minutes (good). Released packer and ran in and released BP.
8/31/2010	Filled well with 7 bbls. Pulled to 4000' and set BP. Pulled to 3000' and set packer. Tested to 1870 psi for twenty minutes (good). Pulled to 2980' and set packer. Tested to 2230' (would not test - packer leaking due to not enough weight). Pulled out of well and laid down BP and packer. Picke up 8-5/8" full bore tension set packer. Ran in well to 2980' and set packer. Tested to 2230 for twenty minutes (good). Pulled to 2500' and set packer. Tested to 2450 for twenty minutes. Pulled to 2000' and set packer. Tested to 2670 for twenty minutes. (packer unloader not opening.) Pulled out of well and laid down packer. Ran in well with kill string.
9/1/2010	Filled well with 9 bbls. Pulled out of well with kill string. Made up 8-5/8" full bore packer and ran in well to 1500'. Tested to surface with 2890' for twenty minutes (good). Pulled to 1000' and tested to surface with 3110 psi for twenty minutes (good). Pulled to 500' and tested to surface with 3300 psi for twenty minutes (good) Pulled out of well and laid down packer. Made up 7.750 string mill (2) 4-3/4" drill collars and ran in well to 3180'. Pulled to 2800'. Nippled up PGSR.
9/2/2010	Filled well with 2 bbls. Rigged up power swivel and milled from 2950' to 3130'. Criculated clean. Pulled out of well and laid down mill. Made up casing patch and running tools. Applied expoy on casing patch and ran in well (stopped at 2117' top at 2077'). Attempted to work thru. Pulled out of well and laid down casing patch (while laying down patch crew member shut blind rams on patch). Ran in well with kill string to 3200'.
9/7/2010	Filled well with 27 bbls. Pulled out of well with kill string. Made up 7.75 string mill, 4-3/4" drill collar, 7-3/8" stabilizer, and 4-3/4" drill collar. Ran in well to 2077'. Picked up power swivel and reamed to 2150'. Ran in well to 3127'. Pulled out of well and laid down tools. Measured and picked up (2) jts of 7-3/8" wash pipe ran and in well to 3200' with no obstructions.
9/8/2010	Filled well with 4 bbls. Pulled out of well with kill string and laid down wash pipe. Made up WEA casing patch and ran to 2119'. Worked thru tight spot and ran to 2157'. Worked thru tight spot and ran to 2970' (top) and bottom at 3110'. Rigged up and set patch with pump at 4000 psi. Pulled thru with rig at 60,000#.
9/9/2010	Filled well with 5 bbls. Pulled out of well and laid down setting tools and 4-3/4" drill collars. Made up Baker 6.25" inflatable packer and ran in well to 3122'. Dropped ball and set packer with 1500 psi. Tested annulus to surface with 1870 psi for twenty minutes (100 psi loss in twenty minutes). Blew ball with 2000 psi and waited 30 minutes for element to relax. Pulled to 2935'.
9/10/2010	Filled well with 4 bbls. Pulled out of well and laid down packer. Made up 6-5/8" bridge plug and ran in well to 7978'. Set bridge plug and tested to 500 psi. Released from BP and pulled to 7920'. Landed in tubing hanger. Installed BPV and nippled down Class III BOP. Nippled up production tree.
9/13/2010	Rigged down hoist and loaded out equipment .
10/15/2010	Spotted tanks mud pump. Moved in and rigged up.

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RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION
DIVISION OF OIL, GAS, AND GEOTHERMAL RESOURCES

HISTORY OF OIL OR GAS WELL

Operator: Southern California Gas Company
Field: Aliso Canyon
County: Los Angeles
Well: Standard Sesnon 25 A
Surface Location: Sec 28 3N 16W S.B.B.M.
A.P.I. No. 03721322
Dan Neville
Title: Senior Storage Field...
(President, Secretary, or Agent)

Date: 12/27/2010
Signature:
~~(Person Submitting Report)~~

Address: PO Box 2300, SC9365, Chatsworth, CA, 91313-2300
Telephone Number: 818-700-3810

History must be complete in all detail. Use this form to report all operations during drilling and testing of the well or during redrilling or altering the casing, plugging, or abandonment, with the dates thereof. Include such items as hole size, formation test details, amounts of cement used, top and bottom of plugs, perforation details, sidetracked junk, bailing tests, and initial production data.

Start Date	Ops. DOGGR Rpt
10/18/2010	Installed BPV plug and nippled down production tree. Nippled up class III BOP. Rigged up working floor and tubing equipment.
10/19/2010	Rigged up tester, installed BPV, and tested blind rams to 300 psi low and 5000 psi high for twenty minutes. Removed BPV and tested pipe rams to 300 psi low and 5000 psi high for twenty minutes. Tested Hydril to 300 psi low and 3000 psi high for twenty minutes. Tested all control valves and inside BOP, TIW valve to 300 psi low and 5000 psi high. (M Davis DOGGR waived witness of BOP test). Unlanded tubing and ran in well to 8025'. Engaged and released bridge plug. Pumped 50 bbls with full circulation (10 bbls to fill). Pulled out of well laying down 3-1/2" tubing to 7500'. Took gas kick circulation out gas cut fluids.
10/20/2010	Filled well with 10 bbls. Pulled out laying down 3-1/2 tubing. Pulled out of well and laid down bridge plug. Made up WEA inflatable test packer and ran in well to 3070'.
10/21/2010	Filled well with 5 bbls. Pulled to 3045', dropped dart and pressured to 2200 psi to set packer. Pressured annulus to 1870 psi for one hour (425 psi loss) Rigged up Western wireline, ran in well and retrieved dart. Pulled out of well with packer to 2950', dropped dart and pressued packer to 2200 psi to set packer. Pressured annulus to 2230 psi for one hour (no psi loss). Ran in well with wire line and retrieved dart. Pulled out of well and laid down packer. Ran in well with kill string to 3172'.
10/25/2010	Filled well with 15 bbls. Pulled out of well laying down kill string (104 jts.). Changed pipe rams to 5-1/2" and rigged up casing tongs. Made up 1 jt 2-7/8" tubing with mule shoe, ball seat, 6-5/8" HES G-77 hydraulic set packer, crossover, 1 jt 3-1/2" tubing, no/go nipple, 1 jt 3-1/2" tubing, 3-1/2" sliding sleeve, 7 jts 3-1/2" tubing, gas lift mandrel, 1 jt 3-1/2" tubing, 3-1/2" x 5-1/2" crossover. Ran in well with 5-1/2" LT&C casing applying seal lube to threads to 3500'.
10/26/2010	Filled well with 2 bbls. Measured and picked up 203 joints of 5-1/2" 20# LT&C casing to 8170'.
10/27/2010	Filled well with 2 bbls. Picked up 1 jt 3-1/2" tubing, spacing pup joints and tubing hanger. Dropped ball to set packer. Pressured tubing to 2000 psi to set packer. Pressured to 2500 psi to blow ballseat. Landed in tubing hanger with 12,000 lbs compression per HES tubing move. Made up hold down studs and tested annulus to 500 psi for twenty minutes (25 psi loss). Nippled down BOP and nippled up production tree.
10/28/2010	Rigged down hoist and loaded out equipment for rig move. Cleaned location.
10/29/2010	Installed laterals and blind flanges. Cleaned location.

DEC 27 2010

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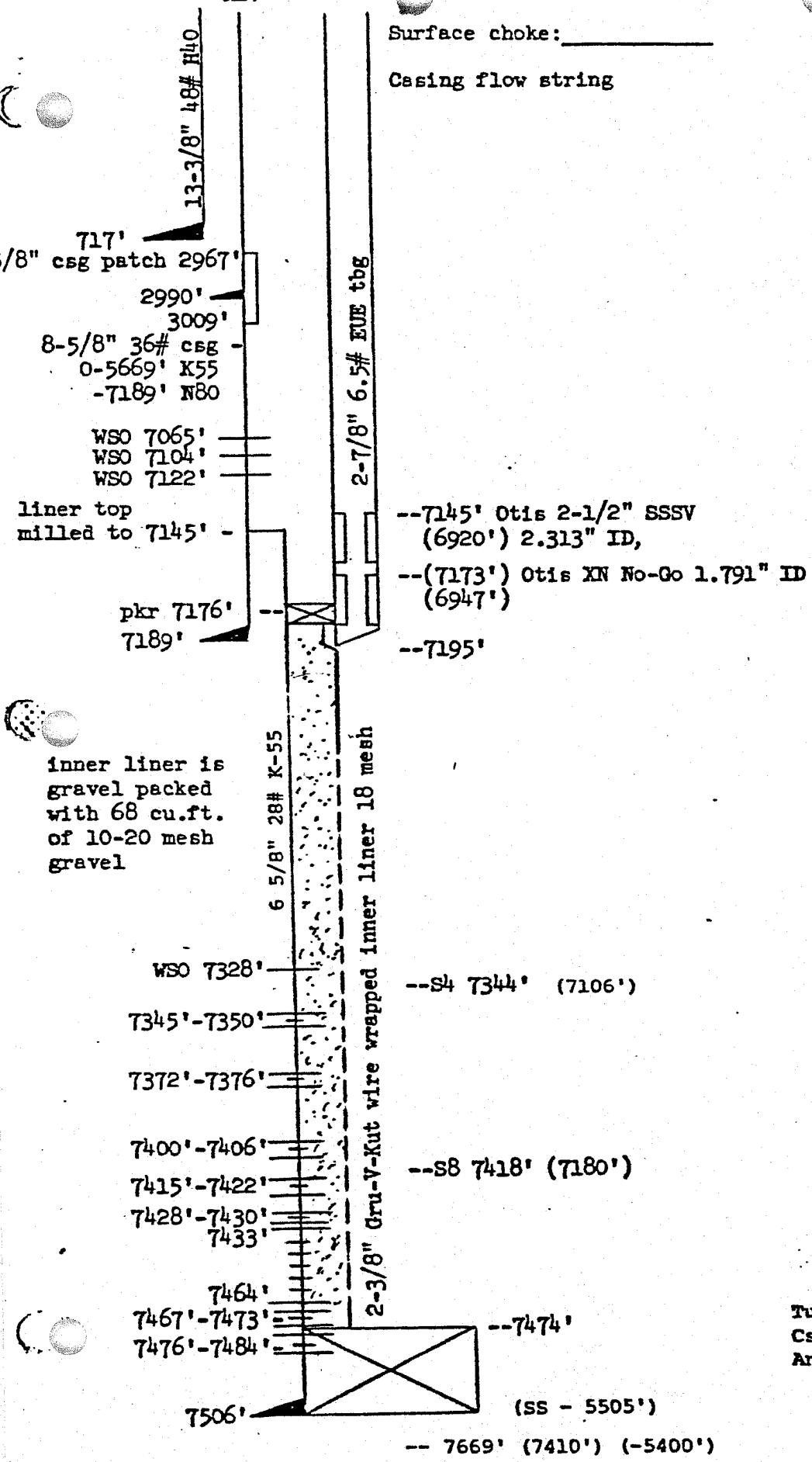
Ex. I - 29

Elevation: 1995' G.L.
KB: 15' M.V. 11'

IW-58



Surface choke:_____

Casing flow string

11/11/72 - Well spud
12/14/72 - Well completed
1/9/73 - 2/19/73 - Pressure tested csg, plugged back to 7474', flow tested perf's & ran tbg with SSSV.
8/28/75 - 9/23/75 - Squeezed at 2990', cleaned out to 7474', washed perf's, ran & gravel packed 2-3/8" inner liner, ran 6-5/8" csg as patch 2926'-3060' & ran tbg with SSSV.
11/2/76 - 7/29/77 - Pulled 6-5/8" csg patch, squeezed at 2990', Triangle Noise Log indicated shoe leak, milled 6-5/8" liner from 7009' to 7145', squeezed WSO holes at 7122', pressure tested csg, ran 8-5/8" csg patch 2967'-3009', cleaned out to 7193', ran tbg with SSSV. Well is currently suspended because 2-3/8" liner is plugged.

WELL VOLUME

	Cu.Ft.	Bbl.
Tubing	234	42
Csg/Lnr.	51	9
Annulus	2068	368

5/30/85

Ex. I - 30

(CHATS)

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION
DIVISION OF OIL, GAS, AND GEOTHERMAL RESOURCES

HISTORY OF OIL OR GAS WELL

Operator: Southern California Gas Company
Field: Aliso Canyon
County: Los Angeles
Well: Fernando Fee 32 E
Surface Location: Sec 27 3N 16W S.B.B.M.
A.P.I. No. 03721321
Todd Van de Putte
Title: Senior Storage Field...
(President, Secretary, or Agent)

Date: 6/7/2013
Signature: Todd R Van de Putte
(Person Submitting Report)

Address: PO Box 2300, SC9365, Chatsworth, CA, 91313-2300
Telephone Number: 818-701-3339

History must be complete in all detail. Use this form to report all operations during drilling and testing of the well or during redrilling or altering the casing, plugging, or abandonment, with the dates thereof. Include such items as hole size, formation test details, amounts of cement used, top and bottom of plugs, perforation details, sidetracked junk, bailing tests, and initial production data.

Start Date	Ops. DOGGR Rpt
3/19/2013	Rigged up the Western wireline unit and ran in the well. Pulled the PXN plug and shifted the sliding sleeve open. Rigged down and moved out the wireline unit.
3/22/2013	Moved in and rigged up the Ensign #321 rig and tied down the hoist. Rigged up to kill the well. Rigged up the associated rig equipment and secured the well.
3/25/2013	Opened the well with 1400 psig surface pressure on the tubing and the casing. Rigged up and pumped 40 bbl of hi-vis HEC polymer and displaced with 110 bbl of 8.5 ppg KCl brine. Killed the well per schedule with 277 bbl of 8.5 ppg KCl brine. Installed the back pressure plug and nippled down the production tree. Nippled up the Class III 5M BOPE and secured the well.
3/26/2013	Rigged up the WEA test truck and the associated test equipment. Pressure tested the blind rams to 300 psig (low) and 5000 psig (high) for twenty minutes. Pressure tested the pipe rams to 300 psig (low) and 5000 psig (high) for twenty minutes. Pressure tested the Hydril annular preventer to 300 psig (low) and 3500 psig (high) for twenty minutes. Pressure tested all the control valves and the choke manifold to 300 psig (low) and 5000 psig (high) for twenty minutes. (All pressure tests held). Changed the pipe rams from 3-1/2" to 4-1/2". Opened the well with 0 psig surface pressure on the tubing and 200 psig surface pressure on the casing. Bled down the casing and filled the well with 80 bbl of 8.5 ppg KCl brine. Backed out the hold down studs. Attempted to release the seals from the packer at 7143', worked the pipe and released the seals from the packer. Rigged up the WEA casing tongs. Pulled out of the well and laid down the 4-1/2" completion casing to 6700'. Circulated gas from the KCl brine and secured the well.
3/27/2013	Opened the well with 0 psig surface pressure on the tubing and 200 psig on the casing. Filled the well with 70 bbl of 8.5 ppg KCl brine and circulated gas cut brine. Pulled out of the well and laid down the 4-1/2" LT&C completion casing. Pulled to 4700' and the packer hung up, worked the pipe and the packer came free. Pulled out of the well to a kill string at 2800' and secured the well.
3/28/2013	Filled the well with 8 bbl of 8.5 ppg KCl brine. Pulled out of the well and laid down the 4-1/2" completion casing. Laid down (3) joints of 3-1/2" tubing, packer and the production equipment, and (3) joints of 2-7/8" tubing. Rigged down the casing tongs, changed the pipe rams form 4-1/2" to 3-1/2". Measured and picked up an 8-5/8" casing scraper and a bumper sub on 3-1/2" tubing. Measured and picked up 3-1/2" tubing to 3800' and secured the well.
3/29/2013	Filled the well with 10 bbl of 8.5 ppg KCl brine. Measured and picked up 3-1/2" tubing to 7145' and secured the well. Shut down the rig for other field operations. Opened the well, pulled out of the well to 5200' and secured the well.
4/1/2013	Opened the well and filled with 15 bbl of 8.5 ppg KCl brine. Pulled out of the well and laid down the casing scraper and installed the shooting flange. Rigged up the Schlumberger wire line unit and associated equipment. Made up the USIT tool on wireline. Ran the USIT log from 7145' to surface. Rigged down and moved out the Schlumberger wireline equipment and nippled down the shooting flange. Ran in the well to a kill string at 2400' and secured the well.
4/2/2013	Pulled out of the well with the kill string. Measured and picked (10) joints of 1" CS Hydrl tubing and crossovers. Ran in the well with 3-1/2" tubing and tagged at 7265'. Attempted to work the tubing down. Nippled up the PGSR, reverse circulated, washed down to 7286' and circulated the well clean. Pulled out of the well to 7140' and secured the well.
4/3/2013	Filled the well with 14 bbl of 8.5 ppg KCl brine. Ran in the well to 7286', cleaned out the 2-3/8" liner. Continued to clean out the 2-3/8" liner to 7409'. Reverse circulated the hole clean, pulled to 7250' and secured the well.
4/4/2013	Opened the well with 0 psig surface pressure on the tubing and the casing. Filled the well with 65 bbl of 8.5 ppg KCl brine. Ran in the well and tagged bottom at 7409'. Attempted to clean out the well and circulated the well clean. (DOGGR - D. Ortiz wavied the clean out depth and witness of the tag). Pulled out of the well to 7240' and secured the well.
4/5/2013	Filled the well with 72 bbl of 8.5 ppg KCl brine. Ran in the well to 7409' and rigged up the HES cementing equipment. Held a safety meeting with crews. Pressure tested the lines to 2000 psig. Pumped 10 bbl of fresh water ahead mixed and pumped 16 bbl (50 sx) of 14.8 ppg Class "G" cement with additives and displaced with 58 bbl of 8.5 ppg KCl brine. Estimated top of cement at 6960'. Pulled out of the well to 6700', rigged up and reverse circulated 90 bbl with a trace of cement to surface. Squeezed from surface with 200 psig surface pressure. Secured the well and cleaned the mud pit.

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION
DIVISION OF OIL, GAS, AND GEOTHERMAL RESOURCES

HISTORY OF OIL OR GAS WELL

Operator: Southern California Gas Company
Field: Aliso Canyon
County: Los Angeles
Well: Fernando Fee 32 E
Surface Location: Sec 27 3N 16W S.B.B.M.
A.P.I. No. 03721321
Todd Van de Putte
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Address: PO Box 2300, SC9365, Chatsworth, CA, 91313-2300
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Start Date	Ops. DOGGR Rpt
4/8/2013	Opened the well with 0 psig surface pressure on the tubing. Filled the well with 10 bbl of 8.5 ppg KCl brine. Tagged the top of cement at 6997' (E Blivens - DOGGR waived the witness of tag). Pulled out of the well and laid down (10) joints of 1" CS Hydril tubing with crossovers. Made up the WEA 8-5/8" test packer on 3-1/2" tubing and ran in the well to 6900'. Filled the well, set the test packer and pressure tested below the packer to 500 psig surface pressure for twenty minutes (The cement plug and casing below the test packer held pressure). Pressure tested the tubing/casing annulus to 500 psig (Pressure bled down 100 psig in 10 minutes). Released the test packer and secured the well.
4/9/2013	Filled the well with 2 bbl of 8.5 ppg of KCl brine. Pulled out of the well to 5000', filled the well and set the test packer. Pressure tested below the test packer to 1240 psig surface pressure (pressure leaked off 1000 psig in 10 minutes). Pressure tested the tubing/casing annulus to 1240 psig (pressure leaked off 400 psig in 10 minutes). Released the test packer, ran in the well to 6000' and filled the well. Set the test packer and pressure tested below the test packer to 800 psig surface pressure (held pressure). Released the test packer, pulled out of the well to 5811' and pressure tested below the test packer to 879 psig surface pressure (held pressure). Released the test packer, pulled out of the well to 5711', and set the test packer. Pressure tested below the test packer to 925 psig surface pressure (pressure leaked off 700 psig in 10 minutes). Released the test packer, ran in the well to 5741' and set the test packer. Pressure tested below the test packer to 912 psig surface pressure (pressure leaked off 700 psig in 10 minutes). Released the test packer, ran in the well to 5780' and set the test packer. Pressure tested below the test packer to 800 psig surface pressure (leak estimated between 5741' and 5780'). Pulled out of the well to 3500', set the test packer and pressure tested the tubing/casing annulus to 1900 psig surface pressure (pressure leaked off 600 psig in 10 minutes). Released the test packer, pulled out of the well to 2800' and set the test packer. Pressure tested the tubing/casing annulus to 2200 psig surface pressure for 10 minutes (held pressure) (Squeeze holes at 2990' leaking). Released the test packer and secured the well.
4/10/2013	Filled the well with 3 bbl of 8.5 ppg KCl brine. Pulled out of the well and laid down the test packer. Ran in the well with 3-1/2" tubing to 6100'. Pulled out of the well, laid down the 3-1/2" tubing to 3000' and secured the well.
4/11/2013	Pulled out of the well and laid down the 3-1/2" tubing. Changed pipe rams from 3-1/2" to 2-7/8". Changed the pipe trailers, measured and picked up 2-7/8" tubing to 4800'. Held BOP drill and secured the well.
4/12/2013	Measured and picked up 2-7/8" tubing to 6012' and landed in the tubing in the hanger. Loaded the pump and the hoses, secured the well and cleaned the location.
4/15/2013	Nippled down the Class III 5M BOPE and nippled up the production tree. Loaded rig and associated equipment. Rigged down the hoist and spotted tanks at FF 32 D. Rigged down the rig equipment and cleaned the location.

Ex. I - 31

Due to the large file size, this exhibit is an excerpt. The native file of this document is available upon request.

SUBMIT IN DUPLICATE

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION

DIVISION OF OIL AND GAS

DIVISION OF OIL AND GAS
RECEIVED
JUL 18 1986
VENTURA, CALIFORNIA

History of Oil or Gas Well

Operator Southern California Gas Co. Field Aliso Canyon County Los Angeles
Well IW #58, Sec. 27, T 3N, R 16W SB B. & M.
A.P.I. No. 037-21321 Name J. W. Gourley (Person submitting report) Title Agent (President, Secretary or Agent)
Date July 17, 1986

Signature N.W. Buss 7/17/86
N.W. Buss for J.W. Gourley

Box 3249, Terminal Annex, Los Angeles, CA 90051 (Address)
(213) 689-3925 (Telephone Number)

History must be complete in all detail. Use this form to report all operations during drilling and testing of the well or during redrilling or altering the casing, plugging, or abandonment with the dates thereof. Include such items as hole size, formation test details, amounts of cement used, top and bottom of plugs, perforation details, sidetracked junk, bailing tests and initial production data.

Date	
	GWO No. 90927: was issued to recover packer/liner and regravel pack a new liner
1986	
3-14	Loaded out rig at Porter Fee #1. Moved to IW #58 and set in rig. Rigged up. Laid 2" line to wellhead.
3-15	Circulated well and removed 8" xmas tree. Installed 9" BOPE. Tested choke manifold, blind rams, pipe rams to 3000 psi; Hydril bag to 2300 psi. Test witnessed by Stephen P. Mulqueen of the D.O.G. Attempted to release from Baker packer at 7176'.
3-17	Attempted to unlatch from packer for 3 hours. Rigged up wireline. Ran free point tool. Tool did not work. Ran a second free point tool and found tubing stuck in seals. Ran string shot. Made backoff at No-Go nipple at 7172'.
3-18	Pulled out of well, laying down 2-7/8" tubing; found wireline in tubing. Pulled 4000' of wireline out of tubing. Installed flow line. Picked up kelly. Unloaded 2-7/8" drill pipe. Picked up 5-1/2" wash pipe and drill collars, along with 2-7/8" drill pipe.
3-19	Finished running in well with 2-7/8" drill pipe and located top of fill at 7166'. Drilled out fill to 7176' at top of packer. Backscuttled well clean. Mixed 10 sacks sawdust. Circulated well.
3-20	Ran to 7176' and backscuttled clean. Laid down wash pipe. Made up screw-in sub. Ran in and screwed into fish at 7166'. Jarred on fish. Released from packer. Pulling out of well with fish.

1986

3-21 Laid down production equipment. Rigged up wireline. Ran CCL. Stopped at 7185'. Pulled out and changed tool. Ran in but were unable to get below 7185'. Ran in well with one joint of 2-3/8" tubing with 45° cutoff. Backscuttled clean. Pulling out of well.

3-22 Rigged up wireline and ran in to 7192'. Pulled out of well. Made chemical cut in extension at 7189'. Ran in well with packer recovery tool to 7176'. Attempted to release packer; did not release. Pulled to kill string. Secured well.

3-24 Filled well with 4 bbls. Pulled out of well with tool. Checked tool and ran in well. Latched into packer and jarred on packer with 50,000# over string weight. Released from packer. Laid down tools. Rigged up wireline and ran in well to packer at 7176'. Fired string shot. Ran in well with 2-3/8" perforated pup joint on 2-7/8" drill pipe. Worked perforated pup joint inside packer while circulating at 3.7 bbls. per minute at 2200 psi.

3-25 Filled well with 2 bbls. Pulled out of well. Made up retrieving tool with bumper sub, jars, three drill collars and ran in well. Latched packer at 7176'. Jarred on packer. Would not release. Released from packer.

3-26 Laid down packer retrieving tool. Made up inside mechanical cutter and ran in well on 2-7/8" drill pipe. Made cut 53" below top of packer. Laid down tool. Picked up packer retrieving tool. Ran in well with bumper sub, jars and drill collars on 2-7/8" drill pipe. Latched into packer. Jarred on packer at 50,000# over string weight. No movement. Released from packer. Secured well.

3-27 Filled well with 2 bbls. Pulled kill string. Laid down packer retrieving tool. Made up 5-1/2" O.D. mill shoe, two junk subs, jars, drill collars. Ran in well on 2-7/8" drill pipe. Ran in to top of packer at 7176'. Milled over packer to 7178' and pulled up to top of packer. Circulated and cleaned well. Pulled out of well to kill string and secured well.

1986

3-28 Finished pulling out of well. Laid down mill shoe. Picked up packer retrieving tool. Ran in with bumper sub, jars, drill collars on 2-7/8" drill pipe. Latched into packer. Pulled 30,000# weight to release packer. Appeared latch released. Latched into top of packer. Began jarring at 50,000# over string weight. Had 8" up movement in 4 hours. Continued jarring with no movement. Released from packer and secured well.

3-29 Removed packer retrieving tool. Picked up 5-1/2" O.D. x 4-7/8" I.D. washover shoe, two junk subs, jars and drill collars and ran in on 2-7/8" drill pipe. Located top of packer at 7175', one foot high. Washed over to 7177' and milled on packer and rubbers to 7178'. Circulated bottoms up.

3-31 Changed out washover shoe. Ran in to 7175'; washed over packer to 7178'. Milled 6" on packer. Circulated well clean.

4-1 Pulled out of well with top sleeve from packer on outside of wash pipe. Laid down wash pipe. Made up latching tool and ran in and latched packer at 7175'. Pulled out of well. Laid down fish, including packer, 4-1/2" ported extension, lower seal bore, 4" lower extension, 2-7/8" 8rd x 4" 8rd crossover, 2-7/8" 8rd x 2-3/8" 8rd crossover and top half of shearout safety.

4-2 Ran in well with 300' of wash pipe with mill shoe on bottom. Ran in and located top of sand at 7222'. Cleaned out sand over liner to 7380' and circulated bottoms up. Recovered no sand. Would not backscuttle. Washed to 7411', but would not backscuttle. Washed up, laying down single to top of liner at 7176'. Pulled two stands and secured well.

4-3 Worked into top of liner at 7176'. Washed and backscuttled over liner to 7416'. Unable to backscuttle. Circulated and worked pipe out of liner to 7176'. Backscuttled bottoms up. Pulling out of well.

4-4 Made up outside cutter tool on 120' of wash pipe. Ran in and worked over fish at 7176'. Tool stopped at 7209'. Unable to work down. Cut 2-3/8" tubing at 7205' and pulled out. Recovered 10' including shearout sub and 2-3/8" tubing. Made up overshot. Ran in and latched onto fish. Jarred on liner for 2-1/2 hours.

1986

4-5 Rigged up wireline and ran free point, which stopped at 7213'. Released overshot and pulled out of well. Made up wash pipe. Ran in, worked and washed over fish from 7205'-7474'. Circulated bottoms up. Pumped 60 bbls. high viscosity pill and circulated well clean. Circulated and worked out of liner. Backscuttled clean at 7146'. Pulled out of well.

4-6 Stood back wash pipe and made up overshot. Ran in and latched onto fish at 7205'. Worked loose and pulled out of well. Laid down 266' of 2-3/8" liner. Laid down wash pipe and made up sawtooth. Ran in well to 7474'. Backscuttled well. Pulled out of well.

4-7 Made up bit and casing scraper. Ran in well to 7474'. Backscuttled clean. Circulated polymer completion fluid out of well with new clean fluid. Pulled out of well. Ran neutron log from 7466' to 5465'. Ran casing caliper log.

4-8 Made up bridge plug. Ran in and set bridge plug in 6-5/8" at 7155'. Tested casing with 1950 psi for one hour (no pressure drop). Released bridge plug and pulled out of well. Ran tubing-conveyed perforating guns to 7474'. Set RTTS retainer at 7313'. Rigged up surface flow lines.

4-9 Rigged up lines and tested to 3000 psi. Pressured drill pipe to 1150 psi with gas. Pressured annulus to 1500 psi to fire gun. Flowed well to Baker tank for 45 minutes. Filled pipe with 30 bbls. Released retainer and circulated gas out of well. Pulled out of well. Laid down guns. Perforated intervals 7474'-7400' and 7385'-7345'. Ran open ended with sawtooth collar. Backscuttled at 7474'. Pulled out of well. Picked up 7 joints 2-3/8" 8rd liner.

4-10 Found bad weld on wire-wrapped liner. Laid down wire-wrapped liner. Ran in well to top of liner. Pulled out and laid down 2-7/8" drill pipe (244 joints). Ran in well, picking up 2-7/8" tubing. Changed out collars.

4-11 Changed 4300' of 2-7/8" collars. Picked up 2-7/8" tubing to 7205'.

4-12 Ran in to 7473'. Circulated and filtered fluid in well. Pulled out of well to kill string. Inspected wire-wrapped liner. Rig on standby waiting on welder to weld centralizers on liner.

1986

4-13 Welded centralizers on 2-3/8" liner. Pulled kill string. Picked up 5 joints (196') 2-3/8" 10rd, 0.006 wire-wrapped liner, including one blank joint. Picked up 193' of 1" pipe. Made up gravel pack tools. Ran in well. Could not work gravel pack cup tool down liner. Pulled out of well. Laid down wire-wrapped liner. Ran in well with 6-1/4" tapered mill and dressed liner top. Circulated bottoms up.

4-14 Ran 197.34' of 2-3/8" liner on over-the-top gravel pack tool. Liner includes 140.46' of 6-gauge wire-wrapped screen with 1' bull plugged blank on bottom and 56.5' of blank, crossover and landing nipple on top. Installed 193' of 1" pipe in liner and landed assembly at 7474'. Pressure tested lines to 3000 psi. Recorded circulating pressures. Closed back side and recorded 900 psi injection pressure, pumping at 1 bbl./minute. Pumped 5 bbls. prepad, 15 bbls. of 15#/gallon slurry, 5 bbls. backpad at 1 bbl./minute - no sand out. Mixed 25 sacks more gravel and pumped at 1 bbl./minute. Sanded out and repressured 4 times to 2750-2300 psi. Reversed out two tubing volumes. Estimated 78 sacks of gravel in place. Waited two hours. Retested pack to 2300 psi. Pulled out of well with gravel pack tools. Made up Baker lead seal for 6-5/8" casing.

4-15 Ran in well and set Baker lead seal adapter on 2-3/8" liner. Top at 7272'. Released tool and pulled out. Rigged up wireline and ran junk ring to 7272'. Made up Otis 6-5/8" 28# "WB" packer. Packer hung up when running in well from 5433'-7145'. Set packer at 7240'. Pulled out of well, sticking coming out of well from 7145'-4500'. Ran in well and tested packer and seals. Tested to 1500 psi for 30 minutes. Seals hanging up while pulling out at 5433'. Ran kill string.

4-16 Laid down kelly. Rigged up Hydro-Test and made up production equipment, hydrotesting tubing in well at 5000 psi. Spaced out and landed 12,000# on packer. Pulled 20,000# over tubing weight to check latch. Tested xmas tree to 5000 psi for 20 minutes.

4-17 Circulated 63#/cu.ft. polymer completion fluid out of well with inhibited salt water. Released rig at 6:01 a.m., 4-17-86.

Ex. I - 32

Well
Fernando Fee 32E

API #: 04-037-21321-00
Sec 27, T3N, R16W

Cut CSG 6' BGL & Welded on Plate
13-3/8" TOC Surface
9-5/8" ETOC Surface

Inner Casing (2/7/2019) 116'
9-5/8" (8.681" ID), 47#, L-80
0' - 67' Hyd. 563
67' - 116' LT&C
17-1/2" Hole (to 720')
CMT'D w/ 6 BBLS‡‡‡ thru 3/4" TBG hung @ 76' in annulus

Surface Casing 717'
13-3/8" (12.715" ID), 48#, H-40, ST&C
0' - 717'
CMT'D w/ 596 CF,
Good CMT Returns to Surface

Shot Holes 1630' - 1635'
(‡3 BBLS SQZ'D Away, 9/15/2017)

11" Hole (720' - 7190')

Stage Collar 2988'

8-5/8" ETOC (1st Stage) 3299'

Six (6) HPF 4135' - 4140'
(†††2.4 BBLS SQZ'D Away, 9/13/2017)

Six (6) HPF 5110' - 5115'
(†1.6 BBLS SQZ'D Away, 9/11/2017)

Six (6) HPF 6065' - 6070'
(***SQZ'D, Press built to 1200 psi immediately & held 15 min, 9/8/2017)

Six (6) HPF 6467' - 6472'
(unable to get inj. rate, no bleed off, ‡‡‡SQZ'D, press. up to 1500# & held solid, 9/6/2017)

Production Casing
8-5/8" (7.825" ID), BT&C
680' (Stub) - 5669' 36#, K-55
5669' - 7189' 36#, N-80
CMT'D w/ 1004 CF (1st Stage) + 911 CF thru Stage Collar @ 2988' (2nd Stage), No CMT Returns to Surface (2nd Stage)

7189'

Inner Liner (4/14/1986)
2-3/8" (1.995" ID), 4.7#, J-55
7272' - 7474'

7272'

7-5/8" Hole (7190' -7515')

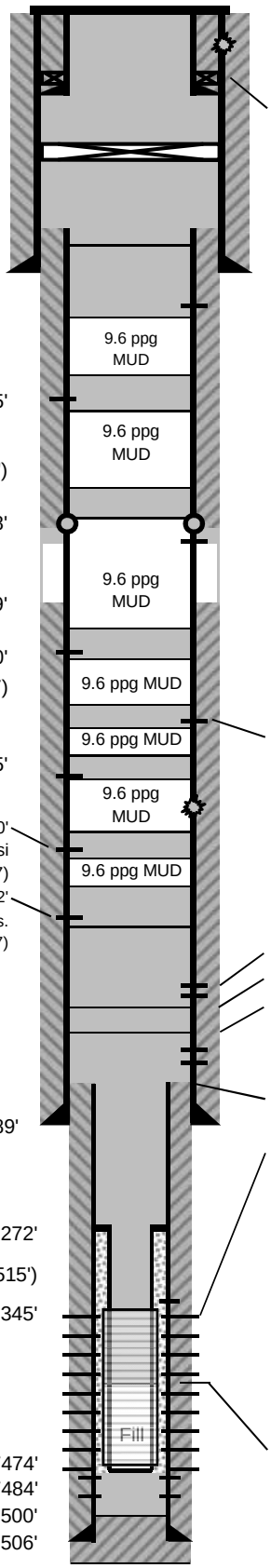
7345'

CMT'D Liner
6-5/8" (5.791" ID), 27.65#, K-55, SFJ
7145' - 7506'

CMT'D w/ 125 SKS* + 25 SKS CMT SQZ'D Away thru TOL

7474'
7484'
Top of CMT 7500'
7506'

TD 7515'
TVD (7271')
Directionally Drilled: Yes (TD is 1134' W, 793' N of Surf)



Surface - 376' CMT Plug (376 CF)
36' Hole in 13-3/8" CSG (9/25/2018, ‡‡‡CMT'D)
76' Top of 9-5/8" Swell Packer
376' - 385' Inflation Packer (2/7/2019)
385 - 700' CMT Plug (577 CF in 2 Stages, C/O f/ Surface)
680' 8-5/8" CSG Stub & ETOC (2nd Stage)
700' - 821' CMT Plug (9 BBLS Down SQZ'D‡‡)
800' - 805' Shot Holes (Negative Inj. rate,‡‡SQZ'D, 9/18/2017)
1506' - 1645' CMT Plug (9 BBLS Down SQZ'D‡)
2814' - 2980' CMT Plug (9 BBLS)
2990' Four (4) 1/2" Holes (44 SKS CMT SQZ'D Away, 9/11/1975 + 105 SKS CMT SQZ'D Away, 5/31/1977 + Calc'd 21 CF SQZ'D Away, 8/11/2016)
4018' - 4150' CMT Plug (7.5 BBLS Down SQZ'D†††)
4721' - 4844' CMT Plug (50 CF/38 SKS Down SQZ'D††)
4829' - 4834' Six (6) HPF (††1.6 BBLS SQZ'D Away, 9/12/2017)
5001' - 5123' CMT Plug (50 CF/38 SKS Down SQZ'D†)
5741' - 5780' CSG Leak (Calc'd 28 CF SQZ'D Away, 8/10/2016)
5904' - 6087' CMT Plug (61 CF/34 SKS SQZ'D***)
6222' - 6506' CMT Plug (62 CF/34 SKS SQZ'D‡‡‡)
6506' - 6941' CMT Plug (172 CF/95 SKS, 8/20/2016)
6930' - 6932' Eight (8) 0.44" Holes (8/19/2016, CMT'D Off by Plug)
6941' - 7006' CMT Plug (34 CF/19 SKS, 8/18/2016)
7006' - 7409' CMT Plug (90 CF/50 SKS, SQZ'D, 4/5/2013)
7104' Four (4) 1/2" Holes (Co. WSO, 135 SKS CMT SQZ'D, 7/5/1977)
7122' Four (4) 1/2" Holes (WSO, 12/3/1972, See Notes**)
7145' TOL & TOC (See Notes**)

6-5/8" Perfs:
7345' - 7385', 7400' - 7474' Eight (8) 0.41" HPF (4/9/1986)
7345' - 7350', 7372' - 7376', 7400' - 7406', 7415' - 7422', 7428' - 7430', 7433' - 7464', 7467' - 7473', 7476' - 7484' Four (4) 1/2" HPF (12/12/1972)

7328' Four (4) 1/2" Holes (Co. WSO, 12/10/1972)

2-3/8" Perfs:
7333' - 7473' 0.006" WWS
Gravel Packed w/ 78 SKS 40-60

7409' C/O Fill (4/4/2013)

7474' - 7500' CMT Plug (2/19/1973)

Operator: So. California Gas Co.
Work Order #: 92873
Lease: Fernando Fee
Field: Aliso Canyon
Status: Abandoned Gas Storage
3000TDS: ±800' (±800')
10000TDS: 4119' (4099')

Ground Elevation: 1995' asl
Datum to Ground: 15' KB
Spud Date: 11/10/1972
Completion Date: 12/14/1972
Abandonment Date: 2/14/2019

Junk: None

Notes

*Partial to full circulation while displacing CMT.
**8-5/8" Shoe leak confirmed 6/2/1977. Milled top of 6-5/8" liner f/ 6998' to 7145' and CMT SQZ'D WSO holes @ 7122' on 6/28/1977 w/ 90 SKS + 38 SKS Away
Holes found in 6-5/8" Liner between 7145' - 7240' in 7/2008

Geologic Zone Markers	md	(tvd)
PGS	1629'	(1628')
A1	4119'	(4099')
A36	4829'	(4788')
UP	5099'	(5041')
LP	5517'	(5420')
UDA1	5858'	(5726')
MDA	6469'	(6297')
LDA	6764'	(6571')
MP	6935'	(6730')
S1	7221'	(6997')
S4	7343'	(7110')
S8	7414'	(7177')
S10	7460'	(7220')
S12	±7489'	(±7247')

Prepared by: CAM (5/3/2016)
Updated by: CAM (4/4/2019)
InterAct

Ex. I - 33

Elevation: 2505' G.L.
KB: 12'
MV: 23'

IW-74

Surface choke: _____

Casing flow string

6/6/73 - Well spud
7/15/73 - Well completed
6/23/76 - 7/3/76 Cleaned out to 7392', ran 2-7/8" tbg with SSSV
8-7-81 - 8-13-81 - Repaired leaking casing patch. Set Pengo 8 5/8" patch @ 2726' - 2773'.

NOTE: Stage collar @ 2793' by original measurement. Later CCI located same @ 2749'.

13-3/8" 48# H40

797'

8 5/8"pengo patch

2726'

Stage Collar 2793'

2773'

2-7/8" 6.5# N-80 EUE tbg

8-5/8" 36# csg
0-5910' K55
-7525' N80

--7338' Otis 2-1/2" SSSV (7268') 2.313" ID

--7368' Otis "XN" No-Go 2.205" x 2.313" (7297')

pkr 7384' -

— x-over 3 1/2" 7379'

--7390'

lnr 7392'

WSO 7500'

7525'

--S4 7525' (7454')

--S8 7583' (7511')

--HZ 7705'

276 cu ft
6-9 gravel
in 14" hole

--Frew 7760' (7686')

6-5/8" 28# K-55 with 30 mesh slots

7932' TD (SS - 5351')

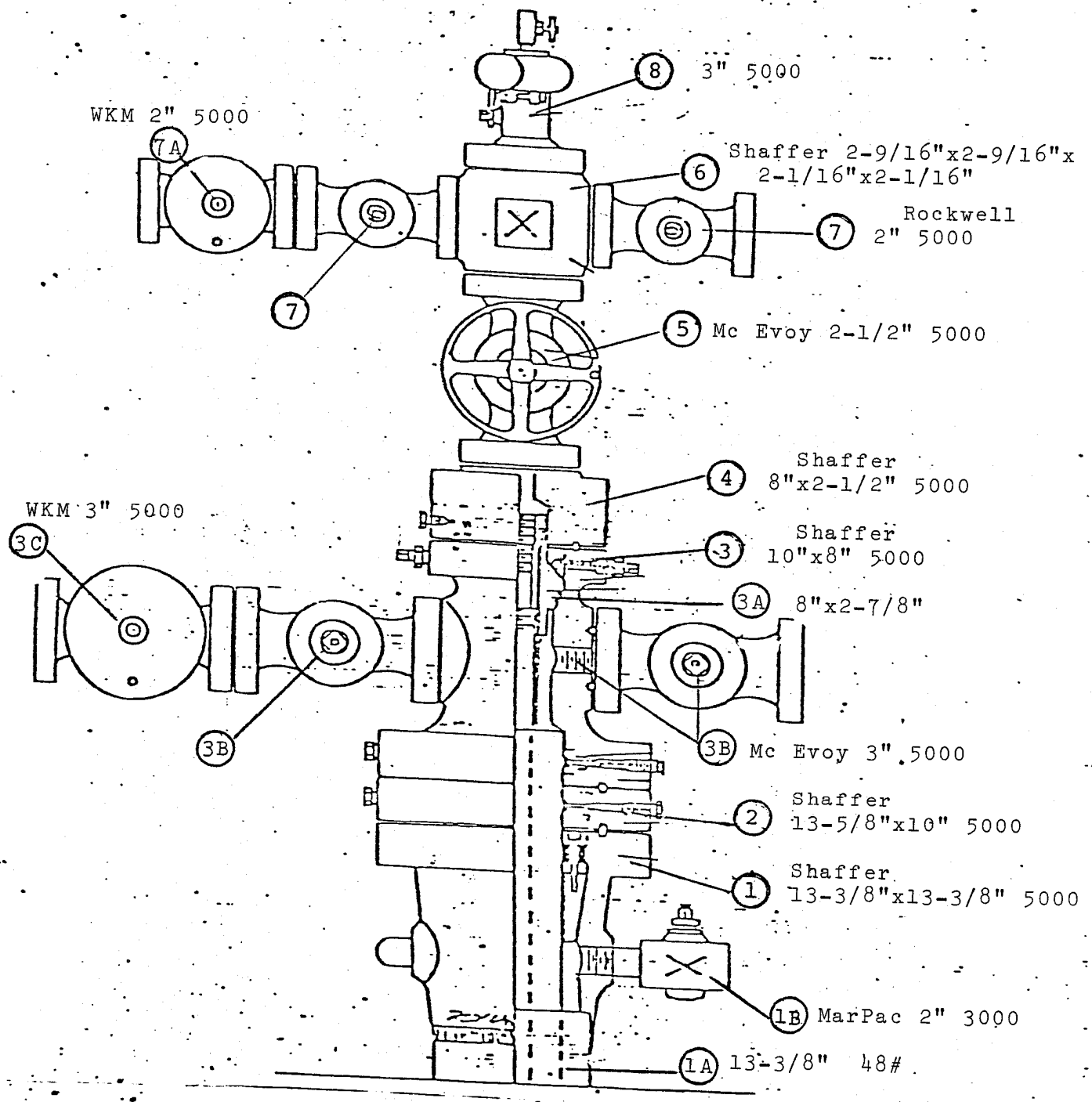
--7992' (7917') (-5400')

WELL VOLUME

	Cu.Ft.	Bbl.
Tubing	240	43
Csg/Lnr.	99	18
Annulus	2133	380

5/30/85

TYPE IV



Well Name: IW 74 - Aliso Canyon

Mfgr.: Shaffer

Date Prepared: 11-30-82

WELLHEAD DESCRIPTION

Well No. IW - 74

Field. Aliso

Date Prepared. 3-19-81

Wellhead Mfgr. Shaffer

1. Casing Head. Shaffer Size. 13-5/8" x 13-3/8" 5000 Type. KD SOW

   Slips & Pack-off. 13-5/8" x 8-5/8" KD

   A. Surface Csg. Size. 13-3/8" Wt. 48# Grade. H-40

   B. Casing Head Valve Maypac Size. 2" 3000 Fig. No. CSB-790-JN

2. Seal Flange. Shaffer Size. 13-5/8" x 10" 5000

   A. Type Seal. PS-63 L.S. Ring. B-160 & R-54

3. Tubing Head. Shaffer Size. 10" x 8" 5000 Type. 55-63 L-1

   Ring. R-54 & Ring. R-50

   Outlets. 2 - 3" Sec. Seal. Lock screw

   Valve Removal Thrd. 2-1/2" line pipe

   A. Tubing Hanger. Shaffer. Size. 8" x 2-7/8" Type. AJO

   B.P.V. Size. 2-7/8" Thrd. 4 LH

   B. Tubing Head Valves. Mc Evoy Size. 3" 5000 Fig. No. 21055

   C. Automatic Csg. Valve. WKM Size. 3" 5000 Fig. No. 114522

4. Adapter Seal Flange. Shaffer Size. 8" x 2-1/2" 5000 Type. AJO

   A. Ring Size. R-50 & R-27

5. Master Valve. Mc. Evoy Size. 2-1/2" 5000 Fig. No. 129

6. Xmas Tree Cross. Shaffer Size 2-1/16" x 2-1/16" 2-1/2" x 2-1/2" Bore Thru. 2-1/2" Across. 2-1/16"

7. Tubing Wing Valves. Rockwell Size. 2" 5000 Fig. No. 21055

   A. Automatic Tbg. Valve. WKM Size. 2" 5000 Fig. No. 110261

8. Unibolt Size 2-1/2" x 3" x 3-1/8" 5000 Inside Thrds. 2-7/8" EUE

9. Wt. Landed in Csg. Head. 270,000 Wt. 36# Grade. K-55 Butt. 8-5/8"

10. Wt. Landed on Doughnut. 34,000 Wt. 6.5 Grade. K-55 2-7/8"

11. Tubing Head to Ground Level. Above 5.20 Below

JN 2 9 1981

MISCELLANEOUS WORK ORDER

M.W.O. NO. 99950

DIVISION No. Basin DEPT. Underground Storage ORG. CODE KZ DATE 6-22-81

THIS M.W.O., WHEN PROPERLY APPROVED, WILL AUTHORIZE A DIRECT EXPENDITURE OF $ 90,000

Aliso Canyon - IW 74 - Storage Well

REASON FOR REQUEST To repair leaking cement stage collar by installing a Pengo casing patch. Rerun tubing with existing safety system and return well to operation.

ESTIMATE OF DIRECT COST

	AMOUNT	
Material	17,000	00
Contract	73,000	00
TOTAL ESTIMATED DIRECT COSTS	90,000	00

%	ACCOUNT	AMOUNT	
100	26280.5	90,000	00

TO BE BILLED TO: (INCLUDE ADDRESS OF BILLEE)

PLANT ACCOUNTING APPROVAL:

REMARKS:

REQUESTED BY: J. W. Tenfelder

PREPARED BY: P.D. Yu

EXAMINED & APPROVED BY: D. Guire

MANAGEMENT APPROVALS

SOUTHERN CALIFORNIA GAS CO.—3045B

AC_CPUC_0080247

RECEIVED
JUL 03 1981
TIME_____UGS

SOUTHERN CALIFORNIA gas COMPANY

INTEROFFICE CORRESPONDENCE

Dists/mlw 6/23/81

TO Mr. J. W. Tenfelder FROM G. C. Abrahamson GCA DATE 6-11-81

SUBJECT Program, material request, budget cost estimate and DOG NOTICE to repair stage collar leak at IW #74, Aliso Canyon.

Please find attached a program to repair leak through stage collar at 2793' in IW #74 at Aliso Canyon. The well files show the following current conditions in this well: 13-3/8" cemented 797', 8-5/8" cemented 7525', WSO 4-1/2" holes at 7500', stage collar 2793', 540' 6-5/8" landed 7932', slotted 7932'-7392' and gravel flow packed with 276 cu. ft. of gravel.

We propose to pull tubing and clean out to packer at 7370'. We will locate stage collar at 2793' with collar locator. Set casing patch over stage collar. Run tubing changing to chamfered collars below casing patch. Re-land tubing with Otis safety system that is now in the well.

The DOG NOTICE was sent under separate cover for your handling.

We have estimated 16 - 8 hour tours, 9 calendar days and a total MWO cost of $90,000 for the proposed work.

If you desire any changes in the material presented, please advise.

64-D

WORKOVER PROGRAM

OPERATOR: Southern California Gas Company

FIELD: Aliso Canyon

WELL: IW #74

CONTRACTOR: To be selected

APPROXIMATE LOCATION: From station #84, 580.31'S and 3307.11'W

ELEVATION: Ground level 2505'. Take all measurements from original Kelly bushing, 12' above ground level

SAFETY: Hard hats are to be worn by all personnel on or near a rig. No smoking is permitted within 100' of the wellhead.

PRESENT CONDITIONS:

13-3/8" 48# H-40 cemented 797'
8-5/8" cemented 7525', WSO 4-1/2" holes at 7500' stage collar 2793'.

Detail:

0-5910' 36# K-55
5910'-7525' 36# N-80

540' 6-5/8" 28# K-55 landed 7932', slotted 7932'-7392'. Gravel flow packed with 276 cu. ft. of 6 - 9 gravel in 14" hole.

TUBING DETAIL:

Otis 8-5/8" Permatrieve packer 7370'
2-7/8" tubing landed 7378'
Otis production tube
Otis 4 seals
Otis latch-in-locator
Otis 10' blast joint
Otis 1.791" NO-GO nipple
Otis 20' blast joint
Otis 2-7/8" annular flow safety system

Gas leak is reported through stage collar at 2793'.

PROGRAM:

1. Move in and rig up with Baker tank.

2. Kill well with 74#/cu. ft. HEC polymer completion fluid. Pump down tubing at about 3 bbls per minute and bleed off gas to Gas Company system. Obtain assistance from Aliso Canyon shift foreman when killing well. Volume of well = 500 bbls.

3. Install back pressure valve in doughnut and remove xmas tree. Send tree in for inspection and repairs.

4. Install H&H oil tool 8" 5000 psi Class III BOPE. Equipment to include 2-7/8" pipe rams, blind rams and Hydril bag with 80 gallon 1500 psi accumulator with remote stations and auxiliary nitrogen. Also install 8" 5000 psi spool with choke and kill line with a check valve. Choke manifold to be connected to the Gas Company system with block valve and bleeder as well as connections to Baker tank. Kill line to be connected to contractor's mud pump. Use all steel lines. Use new API rings on all untested BOPE connections.

5. Pressure test pipe rams and complete shut-off rams to 4000 psi with water. Pressure test choke manifold to 4000 psi with water. Pressure test Hydril bag to 3000 psi with water. The Division of Oil and Gas to be given sufficient notice to allow a witness to be present.

6. Unlatch from packer and pull 2-7/8" tubing. Lay down Otis production equipment. Otis to pick up equipment and clean, inspect and pressure test for reuse in this well. Run 7-5/8" bit and casing scraper and clean out to packer at 7370'.

7. Run collar locator and locate stage collar now reported at 2793'. Set "Pengo" casing patch over stage collar from 2773'-2813'. Adjust depth of patch according to collar locator.

8. Run 2-7/8" tubing with locator and two seals. Set 10,000# on packer. Close pipe rams and pressure test seals and packer to 1500 psi. Keep tubing full and observe for returns. Change to chamfered collars below casing patch.

9. Rerun tubing applying Baker seal, drifting and hydrotesting to 5000 psi holding each test for 1 minute.

Tubing to Include:

Otis production tube
Otis 3 seals
Otis latch-in-locator
Otis 10' heavy wall tube
Otis 2.205" NO-GO nipple
Otis 20' heavy wall tube
Otis 2-7/8" annular flow safety system

10. Space out and land tubing on packer with up to a maximum of 10,000#. Pull 30,000# over weight of tubing to check latch.

11. Set back pressure valve in doughnut. Remove BOPE and install xmas tree. Pressure test xmas tree at 5000 psi with oil for 20 minutes.

12. Circulate polymer completion fluid out of well with waste salt water. Tighten all wellhead bolts. Check all wellhead valves closed. Install blind flanges on all wellhead valves. Release rig.

GCA

G. C. Abrahamson
6-11-81

Approved: J. W. Tenfelder

cc: Rig Supervisor
Relief Rig Supervisor
Contract Pusher (2)

Kern Guppy
M.E. Melton
J.W. Tenfelder

Well File

Ex. I - 34

Due to the large file size, this exhibit is an excerpt. The native file of this document is available upon request.

DOGGR Dist2@DOC

From: Kroh, Jovy E <JKroh@semprautilities.com>
Sent: Wednesday, May 3, 2017 3:24 PM
To: DOGGR Dist2@DOC
Cc: Iguaz, Jose; McMahon, Thomas D.
Subject: 03721357 Rework Porter 26B
Attachments: 03721357_Rework_05-03-2017.pdf

Hello,
Please see attached NOI to rework Porter 26B.
I will be out on leave starting May 15, returning June 13. During this time Jose Iguaz (661-384-5337 / 818-700-3889) will be the main contact for this well.

Thanks,
Jovy

Jovy Kroh
Southern California Gas Company
Sr. Gas Storage Field Engineer
Direct: 818-725-1119
Cell: 937-239-0279

DIVISION OF OIL, GAS, AND GEOTHERMAL RESOURCES

CHECK LIST-RECORDS RECEIVED AND WELL STATUS

Operator: **Southern California Gas Company** WELL DESIGNATION **"Porter" 26B**

API No. **03721357** SE **28** T: **3N** R: **16W** , **SB** B. and M.

County: **Los Angeles** FIELD: **Aliso Canyon**

Type of Notice: **Supplementary** **Date** **6/20/2017** **Report Number:** **P217-0188**

RECORDS RECEIVED (ATTACH PAGES IF REQUIRED)

	Date	OK	NEED	Remarks
Well Summary (OG100)				
History (OG103)				
E-Log				
Mud Log				
Dipmeter				
Directional				
Core and/or SWS				

NEW STATUS

DATE: _____

NOTICE OF RECORDS DUE

DATE: _____

DATE: _____

DATE: _____

DATE: _____

WELL STATUS INQUIRY

DATE: _____

DATE: _____

Well Stat

Change Required: _____

Change Done: _____

ABANDONMENTS/REABANDONMENTS/DRILLS/REDRILLS

CalWims Abandonment Form: _____ SURFACE INSPECTION NEEDED _____ COMPLETED _____
Date and Inspector

FINAL LETTER NEEDED _____ COMPLETED _____ Calwims DRILL/REDRILL Form _____
(Date)

ENGINEER'S CHECK LIST

T-REPORT(S) _____ OPERATOR'S NAME _____ WELL DESIGNATION _____ SIGNATURE _____

Calwims Location _____ Calwims ELEVATION: _____ CONFIDENTIAL RELEASE DATE: _____ PERMIT REQUIREMENTS MET _____

CLERICAL CHECK LIST

LOCATION CHANGE (OG165) _____ ELEVATION CHANGE (OG165) _____ RELEASE OF BOND (OG150) _____

REMARKS

RECORDS SCANNED: _____
(Date)

RECORDS APPROVED: _____
(Date and Engineer)

Modified OGD2

AOR Datbase _____

RAL RESOURCES AGENCY OF CALIFORNI
DEPARTMENT OF CONSERVATION
DIVISION OF OIL, GAS & GEOTHERMAL RESOURCES
1000 S. Hill Rd, Suite 116 Ventura, CA 93003 - 4458

No. P 217-0188

Old	New
010	010
FIELD CODE	
00	00
AREA CODE	
30	30
POOL CODE	

PERMIT TO CONDUCT WELL OPERATIONS

GS Rework-Return to Production/Injection
"Sesnon-Frew" - Modelo (Miocene-Eocene) Formation

Ventura, California
June 22, 2017

Roberto (Bob) Dentici, Agent
Southern California Gas Company (S4700)
555 West 5th Street, ML 17G4
Los Angeles, CA 90013

Your **Supplementary** proposal to **REWORK** well **"Porter" 26B**, A.P.I. No. **037-21357**, Section **28**, T. **03N**, R. **16W**, **SB** B. & M., **Aliso Canyon** field, **Any** area, **Sesnon-Frew** pool, **Los Angeles** County, dated **6/20/2017**, received **6/20/2017** has been examined in conjunction with records filed in this office. (Lat: **34.315720** Long: **-118.557310** Datum:**83**)

THE PROPOSAL IS APPROVED PROVIDED:

1. Blowout prevention equipment, as defined by this Division's publication No. M07, shall be installed and maintained in operating condition and meet the following minimum requirements: Class **III 5M** on the **8 5/8"** casing or lubricator for wireline work.
2. Hole fluid of a quality and in sufficient quantity to control all subsurface conditions in order to prevent blowouts shall be used.
3. Blowout prevention practice drills are conducted at least weekly and recorded on the tour sheet. A practice drill may be required at the time of the test/inspection.
4. Clean out of the well shall be run from surface to **7932'** or as deep as possible.
5. A **Cement Bond Log** and **Gyro Survey Log** shall be run on the **8 5/8"** casing from ±7932' or as deep as possible.
6. A **Casing Wall Thickness Inspection, Ultrasonic Imaging Tool, Cement Bond Log**, Neutron Log, **Magnetic Flux log,** and **Multi-Arm Caliper Inspection** shall be performed on the **6 5/8"** inner string from shoe to surface to demonstrate that the casing has integrity after installation.
7. The new **6 5/8"** inner string shall be cemented from shoe to **2526'.**
8. The depth of each critical zone present in this well location are: **800', 4255', 4829', 5251', 5560', 5660', 6348', 6608', 7110', 7391', 7468', 7583', 7677'** and **7760'.**
9. Perforation and squeeze operations shall be conducted in the **8 5/8"** casing before installation of the **6 5/8"** inner string based on a review of the **Cement Bond Log**.
10. If perforating and squeeze operations are conducted, the perforation operations shall by performed as follows: **5' long, 4 shots per foot,** and with **90°** phasing and shall be located in a permeable part of the formation, within **25'** from the top of the critical zones. A calculated minimum of **150'** linear in the annular space shall be squeezed.

Continued on Next Page

Blanket Bond Dated: 7/6/1999
UIC Project No. 0100006
cc:

Kenneth A. Harris Jr.
State Oil and Gas Supervisor

Engineer Chris Alcock
Office (805) 654-4761

By
Patricia A. Abel, *District Deputy*

CAL/cal

A copy of this permit and the proposal must be posted at the well site prior to commencing operations. Records for work done under this permit are due within 60 days after the work has been completed or the operations have been suspended. Issuance of this permit does not affect the Operator's responsibility to comply with other applicable state, federal, and local laws, regulations, and ordinances.

OG111 (revised 6/2011)

11. During squeeze operations, pressure during the squeeze operation shall not exceed fracture gradient.
12. Before the inner **6-5/8"** casing string is run and cemented, the **8 5/8"** casing shall be pressure tested from the **6 5/8"** liner top at **7372' to 7300'**.
13. ****Step 17 of the submitted NOI states the operation to place gravel in the 6 5/8" liner. The placement of gravel in the lower portion of the 6 5/8" liner shall not be allowed.**
14. Pressure testing shall be conducted to demonstrate the mechanical integrity of the **2 7/8"** bottom hole assembly.
15. A Temperature and Noise log are run on the well from the packer to surface.
16. Pressure testing shall be conducted to demonstrate the mechanical integrity of the **6 5/8"** inner string.
17. Injection shall be through tubing and packer only. Injection or withdrawal through the casing is not permitted.
18. In all other respects, the provisions of Division Order #1109 and its amendments shall remain in effect.
19. This office shall be contacted by phone prior to making any program changes and no changes are made without Division approval.
20. **THIS DIVISION SHALL BE NOTIFIED TO:**
    a. Inspect the installed blowout prevention equipment prior to commencing **downhole** operations.
    b. Witness the perforating operations determined to be necessary after **CBL** evaluation.
    c. Witness any remedial cement squeezes thru perforations, if necessary, as a result of the casing log evaluation.
    d. Witness a pressure test of the **8 5/8"** casing between the bridge plug and the packer to **3625 psig** for 60 min.
    e. Witness a pressure test of the **6 5/8"** inner string to **3625 psig** for 60 min.
    f. Witness a pressure test of the **6 5/8"** casing to **1,000 psig** and the tubing to **3,700** psig.

NOTE:

1. The base of the freshwater zone is at **800'±**.
2. No operation shall be undertaken or continued that will contaminate or otherwise damage the environment.
3. Please contact this office if the **Cement Bond Log** proposed in Step 6 of the program as soon as possible to make adjustments to the cementing program.
4. This permit is being issued as part of Division Order No. 1109 dated March 4, 2016. Any well that fails any of the testing must be taken out of service and isolated from the storage reservoir pursuant to the Safety Review Testing Regime.
5. The required History of Oil or Gas Well (OG103) shall include a complete description of the required pressure testing. **An updated casing and tubing diagram shall be included with the well history.**
6. **A Well Summary Report (Form OG 100)** and **Well History (Form OG 103)** shall to be submitted to the Division within 60 days after the well is drilled, reworked, plugged and abandoned, or if the work is suspended. Any additional well work will require an additional notice to be submitted to this office prior to resuming well operations.

Enclosure: Attachment 1 to DOGGR Order 1109. Safety Review Testing Regime for the Aliso Canyon Natural Gas Storage Facility

ATTACHMENT 1
TO DOGGR ORDER 1109

SAFETY REVIEW TESTING REGIME
FOR THE ALISO CANYON NATURAL GAS STORAGE FACILITY

This document identifies the requirements of this comprehensive safety review that shall be completed by the Southern California Gas Company (Operator) and verified by the Department of Conservation, Division of Oil, Gas, and Geothermal Resources (Division). The Operator shall use accepted industry practices and procedures.

The Division has consulted with independent technical experts from the Lawrence Berkeley, Lawrence Livermore, and Sandia National Laboratories ("National Laboratories") to develop the requirements of this facility safety review. The National Laboratories experts independently reviewed and concurred with the testing requirements for the safety review detailed below.

This comprehensive safety review requires that each of the active injection wells in the Aliso Canyon Storage 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 storage reservoir. Several steps, detailed below, are required in this safety review. Documentation of all testing required under this comprehensive safety review shall be provided electronically to the Division within 72 hours of completion of a test in digital (i.e. LAS) and printed (i.e. pdf) form. All pressure tests required under this comprehensive safety review shall be witnessed by Division staff. A well that is properly plugged and abandoned in accordance with Public Resources Code section 3208 is not subject to testing under this comprehensive safety review. A well that does not pass all tests must be repaired, retested, and pass all tests, or be plug and abandoned.

REQUIRED TESTS FOR EACH WELL IN THE FACILITY

Step 1: The Operator shall perform an initial casing assessment on the well consisting of temperature and noise logs.

a. Temperature Log:
A temperature survey shall be run from the surface to the packer to measure the temperature within the wellbore. A temperature survey that demonstrates no unexplained anomalous temperature changes in the well is one indication of casing integrity.

b. Noise Log:
An acoustic sensor survey capable of detecting the sound of fluid flow will be conducted the length of the well above the packer to the surface. The survey will include stops at least every 250 feet and at the midpoint of any anomaly detected by the temperature survey. The absence of anomalous sound above the packer is an indication of well integrity

Step 2: The results of the Temperature Logs and Noise Logs will be independently reviewed by Division engineers. Any unexplained abnormal findings in this set of tests shall be addressed by the Operator in one of the following ways:

a. Conduct further investigation and demonstrate to the Division's satisfaction that the abnormal finding is not an indicator of a lack mechanical integrity;
b. Remediate the well to the Division's satisfaction; or
c. With Division review and approval, remove the well from operation and isolate the well from the underground gas storage reservoir in accordance with Steps 4b through 7b below.

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 reviewed by Division engineers to ensure that there are no additional abnormal test results and to confirm the issue was repaired.

Step 3: After these tests are completed on the well, and all required action has been completed, the operator shall either:

a. Conduct the additional tests and evaluations on the well, outlined in Steps 4a through 7a below, in order to gain approval for injecting gas through that well; or
b. Remove the well from operation and isolate the well from the underground gas storage reservoir in accordance with Steps 4b through 7b below.

REQUIRED TESTS IF A WELL IS INTENDED TO RESUME OPERATIONS

If Temperature and Noise Logs have been completed on a well and they indicate well integrity, and the Operator designates the well to return to injection operations, then the Operator shall perform the additional testing outlined in Steps 4a through 7a. The results of these tests will be independently reviewed by Division engineers and posted publicly. Each of the following tests requires that the production tubing be removed from the well.

Step 4a: The Operator shall conduct a **Casing Inspection log.**
The Operator shall conduct a Casing Inspection log of the well that measures the thickness of the production casing, from the surface to the bottom of the gas storage reservoir cap rock. If the inspection reveals a reduction in wall thickness, the current minimum strength of the casing will be calculated. If the current minimum 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 inspection log 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 as authorized in the current Project Approval Letter.*

Step 5a: The Operator shall conduct a **Cement Bond Log** for the well.
The Operator shall conduct a Cement Bond Log (CBL) that measures the bonding between cement and the production casing of the well, and also the bonding between the annular cement and the formation. Cement should be solidly bonded to both the well's production casing and the geologic formation to ensure a seal that prevents fluids from migrating up or down the outside of the well. *A passing test for a cement bond log shows definitive bond, as demonstrated by sonic waveform,*

between cement and casing and between cement and the gas storage formation and/or cap rock for at least 100 feet above the top of the gas storage reservoir.

Step 6a: The Operator shall conduct a **Multi-Arm Caliper Inspection** of the well.
The operator shall conduct an inspection that measures any internal degradation or significant changes to the well's geometry from the surface to the top of the gas storage reservoir, using a minimum 32-arm caliper tool. 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 production casing and of the well once the production tubing has been reinstalled. The Operator may conduct the casing pressure test prior to reinstalling the production tubing. Using a digital recorder, the operator will conduct a liquid-filled positive pressure test within the production tubing of the well, and in the annular space between the production tubing and the casing, to determine the well's ability to withstand normal operating pressures. The production tubing will be isolated and then pressure tested. The annular space between tubing and casing will be pressure tested. This testing also evaluates the integrity of any packers, which seal the annular space between the tubing and casing. The pressure test will be one hour and begin at a pressure of 115% of the maximum operating pressure or the minimum yield strength of the casing and tubing, whichever is less. *A passing pressure test is a pressure loss not exceeding 10% for any 30 minute period during the hour long test.*

After conducting the above tests, the Operator will conduct any indicated remediation so that the well can pass these tests. All remediation will be subject to the review of Division engineers. The well would then be required to undergo the tests once again to demonstrate well integrity.

If the well passes the Casing Wall Thickness Inspection, the Cement Bond Log, the Multi-Arm Caliper inspection and the Pressure Test to the Division's satisfaction, then the Division may clear the well for use for gas injections and withdrawal, once the Division has authorized resumption of injection into the gas storage reservoir. As noted below, wells approved for operation will only be permitted to inject or withdraw gas through the production tubing.

REQUIRED ACTIONS IF THE WELL IS TO BE TAKEN OUT OF OPERATION AND ISOLATED FROM THE GAS STORAGE RESERVOIR:

If the operator elects to take a well out of service, then the following steps shall be taken to isolate the well from the gas storage reservoir:

Step 4b: The Operator shall 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 storage reservoir to shallower geologic zones above the gas storage reservoir. Existing cement bond logs and well construction

records may be used to make this confirmation. This confirmation requires concurrence from Division engineers.

Step 5b: The Operator shall install a mechanical seal or "packer" within the well's production casing and install a mechanical plug within the well's production tubing, if applicable. These seals shall 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: The Operator shall fill the well with fluid to the well's surface in order to create appropriate downward hydrostatic 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 Laboratory 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:

a. 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;
b. Conduct noise log, temperature log and positive pressure test every six months;
c. Conduct weekly monitoring of fluid levels in the well or, 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.

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, and the operator shall take all necessary steps maintain the safety of the well.

Any well taken out of operation cannot be approved to resume operations and gas injection until the successful completion of the battery of tests outlined above in Steps 4a through 7a (Casing Wall Thickness Inspection, the Cement Bond Log, the Multi-Arm Caliper Extension and the Pressure Test) is completed. Those tests must be successfully completed within one year of completing step 6b. If a well cannot successfully complete all necessary steps required in this safety review after one year of completing step 6b, then the well shall be properly plugged and abandoned in accordance with Public Resources Code section 3208.

REQUIREMENTS FOR WELLS RESUMING OPERATIONS IN ALISO CANYON

The Division's authorization to resume injection in the Aliso Canyon Storage Facility will be contingent on the successful completion of this comprehensive safety review. The State Oil and Gas 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, been taken out of service and isolated from the underground gas storage reservoir, or been properly plugged and abandoned in accordance with Public Resources Code Section 3208.

Ex. I - 35

Well
Porter 26B

API #: 04-037-21357-00
Sec 28, T3N, R16W

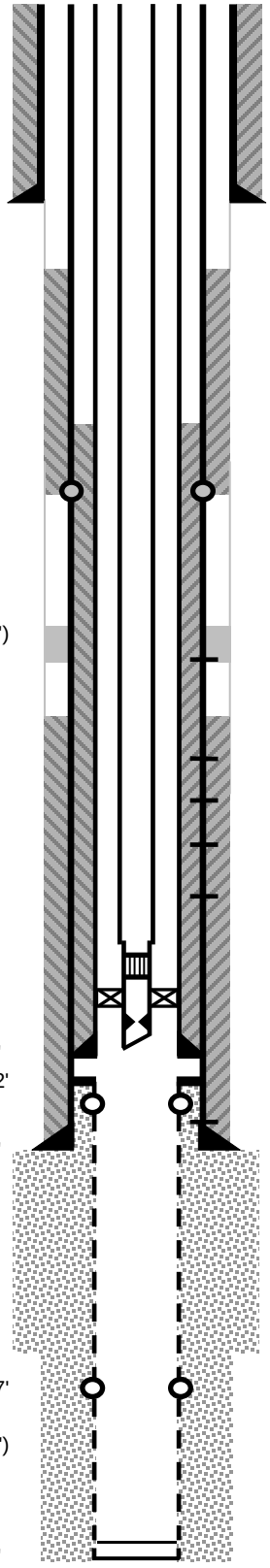
Operator: So. California Gas Co.

Lease: Porter
Field: Aliso Canyon
Status: Active Gas Storage
3000TDS: ±800' (±795')
10000TDS: TBD

Ground Elevation: 2505' asl
Datum to Ground: 12' KB

Spud Date: 6/6/1973
Completion Date: 7/15/1973
Last Rework Date: 8/4/2017

Junk: None



13-3/8" TOC Surface

17-1/2" Hole (to 799')

Surface Casing
13-3/8" (12.715" ID), 48#, H-40, ST&C
0' - 797'
797'

CMT'D w/ 570 CF + 100 SKS,
Good CMT Returns to Surface

6-5/8" ETOC 2609'

Inner Casing (7/18/2017)
6-5/8" (5.921" ID), 24#
0' - 7375'

CMT'D w/ 83 BBLS

11" Hole (799' - 7525')

Production Casing
8-5/8" (7.825" ID), BT&C
0' - 5910' 36#, K-55
5910' - 7525' 36#, N-80

CMT'D w/ 1150 CF + 100 SKS (1st Stg.),
+ 1100 CF thru Stage Collar @ 2793'
(2nd Stg.), No CMT Returns to Surface

7375'
Burns LSA w/ PC below 7392'

7525'

14" Hole (7525' - 7717')

Liner (7/13/1973)
6-5/8" (5.791" ID), 27.65#, K-55, SFJ
7392' - 7932'

Burns PC 7737'

11" Hole (7717' - 7932')

TD 7932'
7932'

Tubing (8/2/2017)
4-1/2" (3.95" ID), 12.6#, Hydril 513
0' - 7290'
3-1/2" (2.992" ID), 9.3#, L-80, Hydril 563
7290' - 7363'

1100' 8-5/8" ETOC (2nd Stage)

Stage Collar @ 2793' (by orig. measurement)
(Later located f/ 2746' - 2749' during collar log run on 8/10/1981)

4174' *8-5/8" ETOC
4250' - 4255' Four (4) HPF (Calc'd 20 CF SQZ'D Away*
+ 7 BBLS SQZ'D Away, 6/29-7/5/2017)
4400' 8-5/8" ETOC (1st Stage)
4819' - 4824' Four (4) HPF (7 BBLS SQZ'D Away, 6/28/2017)
5246' - 5251' Four (4) HPF (7 BBLS SQZ'D Away, 6/27/2017)
5653' - 5658' Four (4) HPF (7 BBLS SQZ'D Away, 6/26/2017)
6604' - 6609' Four (4) HPF (5 BBLS SQZ'D Away, 6/23/2017)
7290' 4-1/2" x 3-1/2" X-Over
7296' Sliding Sleeve (2.813" ID, opens down, closes up)
7340' HES AS1-X PCKR (COE @ 7344', 8/2/2017)
7360' "XN" Nipple (2.75" Profile w/ 2.635" No-Go)
7363' Wireline Re-entry Guide

7500' Four (4) 1/2" Holes (7/6/1973) WSO

Liner Perfs:
7392' - 7523'
2" x 30M, 12R, 6"C SMC Slots
7523' - 7737' & 7760' - 7932'
2" x 30M, 28R, 6"C SMC Slots

Gravel Packed w/
276 CF (92% of Calc'd) 6-9

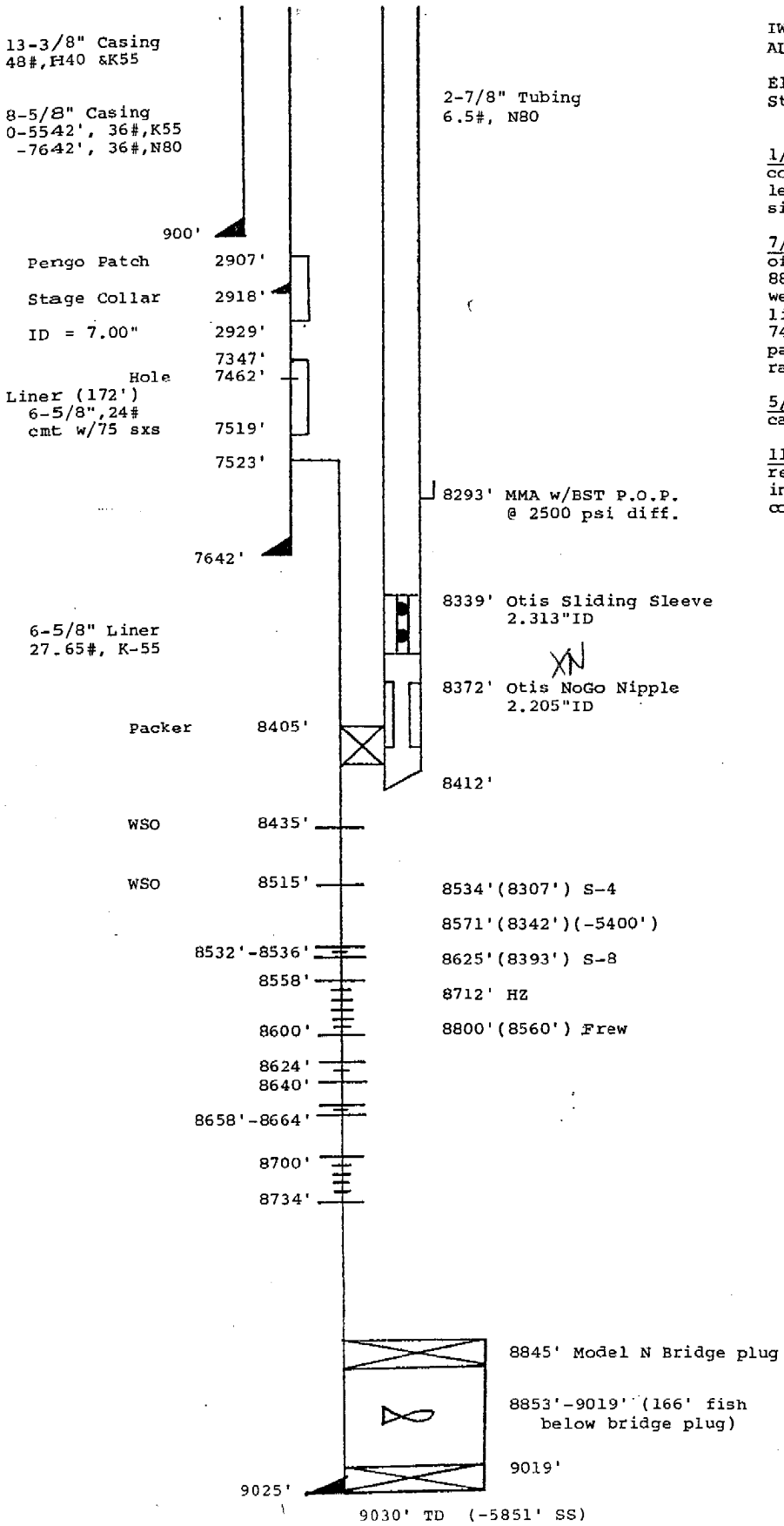
7922' Cleaned out (7/27/2017)

Top of Zone Markers	md	(tvd)
MPupth	4255'	(4222')
A36	4829'	(4793')
UP	5208'	(5170')
LP	5560'	(5520')
UDA1	5660'	(5619')
MDA	6348'	(6299')
LDA	6608'	(6555')
MP	7110'	(7048')
S1	7391'	(7323')
S4	7468'	(7399')
S8	7583'	(7512')
S14	7677'	(7605')
FREW	7760'	(7687')

TVD (7858')
Directionally Drilled: Yes (TD is 196' W, 893' N of Surf)

Prepared by: MAM (5/27/2016)
Updated by: LD (5/16/2018)
InterAct

Ex. I - 36



IW-77
ALISO CANYON FIELD

Elevation: 2927'GL, 15' KB, 13' MV
Status: Injection/Withdrawal Well
Casing flow string

1/13/73-2/25/73: Well drilled and completed. 128' of drilling assembly left @ 7728'-7956' and 7818'-7956', side tracked and cemented.

7/23/76-11/12/76: Cleanout to top of fish @ 8853', set bridge plug @ 8845' to abandon fish and bottom of well, ran and cmtd 172' of 6-5/8" liner to patch hole in casing @ 7462', ran Gearhart-Ownes casing patches 2878'-2910', 2911'-2953' and ran tubing w/SSSV.

5/5/80-6/16/80: Repair gas leak in caprock.

11/21/86-12/4/86: Workover to remove leaking casing patches and installed new casing patch over stage collar.

Volumes

	CuFt	Bbl
Tubing	274	49
Csg/liner	78	14
Annulus	2270	404
Totals	2622	467

JDM:hs
4/29/87

Ex. I - 37

Well
Standard Sesnon 25B ST2

API #: 04-037-21323-02
Sec 28, T3N, R16W

Cut CSG 6' BGL & Welded on Plate
13-3/8" TOC Surface
CIBP (COE @ 56', 2/1/2019) 55'
17-1/2" Hole
8-5/8" ETOC (2nd Stg.) 562' ([‡]Calc'd)[‡‡]
Four (4) 0.5 HPF 799' - 804'
(no comunication or flow, 1/17/2019)
0.43" GSX Deep Penetrating Charges 806' - 811'
([¥¥]14 BBLS Hyd. SQZ'D Away, 1/18/19)
8-5/8" CSG Cut 810' & 820'
(unable to recover, 1/10-11/2019)

Surface Casing 900'
13-3/8" (12.715" ID), 48#, K-55, ST&C f/ 0' - 900'

CMT'D w/ 700 CF* + Top Job in 3 stages (171 CF thru 1" pipe @ 75' + 100 SKS (Class "G", 3% CaCl2) + 189 CF of ready mix pea gravel, 2% CaCl2), CMT to Surface

CMT Ret./CIBP (COE @ 2797', 12/28/2018) 2795'
8-5/8" Stage Collar & ETOC (1st Stage) 2918'
(Located by wireline 12/3/86, See Notes***)
Ret./CIBP (COE @ 3207', 12/26/2018) 3206'

CMT Retainer (COE @ 4476', 12/20/2018) 4475'

11" Hole (to 7650')

Inner Liner (CSG Patch) (10/12/1976)
6-5/8" (5.921" ID), 24# 7347'
7347' - 7519'

CMT'D w/ 75 SKS,
Good Returns to TOL
7519'

7523'

Production Casing
8-5/8" (7.825" ID), 36#, BT&C
0' - 5542' K-55
5542' - 7642' N-80 7642'

CMT'D w/ 1955 CF (1st Stage)
+ 1500 CF thru Stage Collar
@ 2996'*** (2nd Stage),
Full circulation throughout job,
No CMT Returns to Surface[‡]

7-5/8" Hole (7650' - 9030')

6-5/8" Perfs: 8532'
8532' - 8536'**, 8558' - 8600'**, 8624' - 8640',
8658' - 8664', 8670' - 8674',
8684' - 8688', 8700' - 8734'**
Four (4) 0.4" HPF (3/1973, **See Notes)
8532' - 8540', 8558' -8608', 8660' - 8682'
Four (4) ~0.28" HPF (2/9-2/10/2006)
8624' - 8640' Two (2) ~0.28" HPF (2/9/2006)

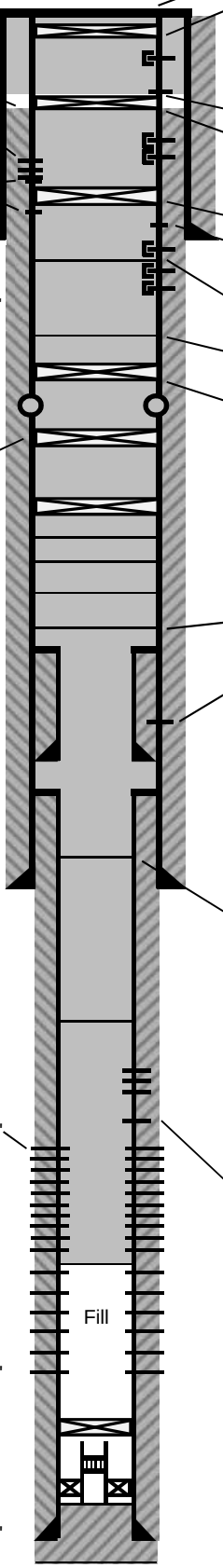
Liner
6-5/8" (5.791" ID), 27.65#, K-55, SFJ 8734'
7523' - 9025'

CMT'D w/ 500 CF,
Good Returns to TOL

PBTD 9019'

9025'

TD 9030'
TVD (8784')
Directionally Drilled: Yes (TD is 1129' E, 165' N of Surf)



6' (BGL) - 55' CMT Plug (8.4 BBLS)
57' Top of CMT (86.5 BBLS Below & thru Perfs[¥¥¥] w/ CMT Returns to Surface
390' Drilled Holes (did not obtain sample)[¥]
549' - 559' (4) 0.4" Sallow HPF (CMT'D[¥¥¥])
560' - 562' CIBP (1/22/2019)
562' - 814' CMT Plug (29 BBLS Hyd. SQZ[¥¥])
570' & 800' Drilled Holes[¥]
814' CMT Ret./CIBP (COE @ 815', 1/16/2019)
817' - 946' CMT Plug (8 BBLS)
865' 8-5/8" CSG Cut (unable to recover, 1/8/2019)
922', 997', 1023' Drilled Holes[¥]
946' - 1849' CMT Plug
(55 BBLS in 2 Stages)
1849' - 2795' CMT Plug
(56 BBLS in 2 Stages)
2799' - 3206' CMT Plug (24.3 BBLS)
3208' - 4475' CMT Plug
(74.5 BBLS in 3 Stages)
4478' - 4520' CMT Plug (2.5 BBLS)
4520' - 4757' CMT Plug (13.5 BBLS)
4757' - 5869' CMT Plug (67.5 BBLS in 3 Stages)
5869' - 6693' CMT Plug (50 BBLS in 2 Stages)
6693' - 7602' CMT Plug (47.5 BBLS in 2 Stages)
7347' Co. WSO on Splice
7462' Hole/Leak in 8-5/8" CSG (10/8/76)
(CMT SQZ'D 2X, 51 CF + 90 CF Away)
7519' Co. WSO on Splice
6-5/8" x 8-5/8" Lap WSO
7585' Sidetrack (ST2) KOP (from ST1) into this wellbore (See History)
7602' - 8297' CMT Plug
(22 BBLS in 2 Stages)
8297' - 8684' CMT Plug (14.5 BBLS, 1.9 BBLS Hydrostatic SQZ'D Away)
8432' - 8433' (4) 1/2" HPF (144 CF CMT SQZ'D Away, 6/5/80)
8434' (4) 1/2" Holes (157 CF CMT SQZ'D Away, 5/17/80)
8434' Reshot (4) 1/2" Holes (72 CF CMT SQZ'D Away, 5/28/80)
8435' (4) 1/2" Holes WSO
8515' (4) 1/2" Holes WSO
8684' Cleaned out Light Metal, Formation Sand & Large Formation Rocks (Unable to Work Below, 11/26/2018)
8845' 6-5/8" Model "N" BP
8853' Top of Junk (see desc. above)

Operator: So. California Gas Co.
Work Order: 92869
Lease: Standard Sesnon
Field: Aliso Canyon
Status: Abandoned Gas Storage
3000TDS: ±800' (±800')
10000TDS: 4688' (4687')

Ground Elevation: 2927' asl
Datum to Ground: 15' KB

Spud Date: 1/13/1973
Sidetrack (ST2) Kick-off Date: 2/13/1973
Completion Date: 3/16/1973
Abandonment Date: 2/1/2019

Junk: 5 JNTs 2-7/8" TBG, Sliding Sleeve, 6-5/8" Baker PCKR, Top of Junk @ 8853'

Wellbore History
Orig. Hole (OH) TD @ 7984'
(See Standard Sesnon 25B)
ST1 KOP @ 7811'
TD @ 7956'
(See Standard Sesnon 25B ST1)
ST2 KOP @ 7585'
TD @ 9030'

Notes
*No circulation throughout job
**Perfs @ 8532' - 8600' treated w/ 60 CF 3% HCl, 276 BBL "Clay Lok". Perfs @ 8700' - 8734' treated w/ 45 CF 3% HCL, 200 BBL "Clay Lok".
***Orig. drilling history reports 8-5/8" Stage Collar at 2996'
[¥]0.281" Drilled Holes for Fluid Samples (Plugged & Monitored Press. Test Successfully, 12/15 - 12/16/2018)
[‡‡]CBL indicated no CMT behind CSG string (1/19/2019)

Geologic Zone Markers	md	(tvd)
A1	4688'	(4687')
A36	5547'	(5545')
UP	5841'	(5834')
LP	6317'	(6290')
UDA1	6674'	(6621')
MDA	7512'	(7356')
LDA	7733'	(7561')
MP	8250'	(8046')
S1	8448'	(8232')
S4	8534'	(8313')
S8	8624'	(8398')
S12	8716'	(8485')
S14	8758'	(8525')
FREW	8798'	(8563')

Prepared by: LD (6/2/2016)
Updated by: CAM (2/14/2019)
InterAct

Ex. I - 38

Due to the large file size, this exhibit is an excerpt. The native file of this document is available upon request.

STATE OF CALIFORNIA
DEPARTMENT OF CONSERVATION
DIVISION OF OIL AND GAS

REPORT ON PROPOSED CHANGE OF WELL DESIGNATION

R.D. Phillips, Agent
Southern Calif. Gas Company
810 S. Flower St.
Los Angeles, CA. 90017

Ventura, California
February 23, 1990

Your request, dated February 13, 1990, proposing to change the designation of wells in Sec. 27, T. 3N, R. 16W, SB B.&M., Aliso Canyon field Los Angeles County, District No. 2, has been received.

The proposed change in designation, in accordance with Section 3203, Public Resources Code, is authorized as follows:

From:		To:
IW 56	(037-21354)	"Porter" 32F (037-21354)
IW 57	(037-21355)	"Porter" 32D (037-21355)
IW 58	(037-21321)	"Fernando Fee" 32E (037-21321)
IW 60	(037-21276)	"Porter" 32B (037-21276)
IW 61	(037-21277)	"Porter" 32A (037-21277)
IW 62	(037-21313)	"Fernando Fee" 32F (037-21313)
IW 73	(037-21358)	"Fernando Fee" 32B (037-21358)
IW 75	(037-21356)	"Fernando Fee" 32D (037-21356)
IW 76	(037-21359)	"Fernando Fee" 32C (037-21359)
IW 77	(037-21323) Sec. 28	"Standard Sesnon" 25B (037-21323)
IW 78	(037-21360)	"Porter" 32C (037-21360)
IW 81	(037-21363)	"Porter" 32E (037-21363)

bb

M.G. MEFFERD, State Oil and Gas Supervisor

By Patrick J. Kinnear
Patrick J. Kinnear, Deputy Supervisor

OGD157

SUBMIT IN DUPLICATE

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION

DIVISION OF OIL AND GAS

DIVISION OF OIL AND GAS
RECEIVED
MAR 9 1987
VENTURA, CALIFORNIA

History of Oil or Gas Well

Operator Southern California Gas Co. Field Aliso Canyon County Los Angeles
Well IW #77, Sec. 28, T 3N, R 16W S.B.B. & M.
A.P.I. No. 037-21323 Name R. M. Morrow (Person submitting report) Title Agent (President, Secretary or Agent)
Date March 6, 19 87

Signature N.W. Buss for R.M.Morrow

Box 3249, Terminal Annex, Los Angeles, CA 90051 (Address) (213) 689-3925 (Telephone Number)

History must be complete in all detail. Use this form to report all operations during drilling and testing of the well or during redrilling or altering the casing, plugging, or abandonment with the dates thereof. Include such items as hole size, formation test details, amounts of cement used, top and bottom of plugs, perforation details, sidetracked junk, bailing tests and initial production data.

Date

MWO No.: 99722: was issued to remove two casing patches and set new casing patch

1986

11-21 Loaded out rig to move from Montebello MGS #15-28 to IW #77 at Aliso Canyon.

11-24 Set in rig on IW #77 and rigged up. Removed xmas tree and installed BOPE. Tested blind rams, pipe rams, choke manifold to 3000 psi; and Hydril bag to 2300 psi. Test witnessed by Bill Winkler of the D.O.G.

11-25 Installed pitcher nipple. Released from packer. Laid down tubing hanger. Circulated bottoms up. Pulled out and laid down production equipment. Ran spear on 4-3/4" drill collars in well. Located patch at 2878'; jarred on top swage and secured well.

11-26 Pulled out of well; did not recover top swage. Ran in and jarred swage loose. Pulled out and recovered swage. Made up fishing tools. Ran in well and jarred casing patch loose. Pulled out of hole and laid down patch. Made up millshoe, ran in and located seal.

11-27 Holiday

11-28 Milled swage loose. Ran in with spear to 2918'. Jarred swage loose. Recovered bottom swage from no. 1 patch and top swage from no. 2 patch. Ran in to 2918' and jarred patch no. 2 loose. Pulled out of hole and laid down patch. Ran in with millshoe to 2900'.

1986

11-29 Milled swage loose at 2923'. Circulated clean and pulled out of well. Laid down all fishing tools. Ran in well with 7-5/8" bit and casing scraper to 7347'. Pulled out and made up 5-5/8" bit and 6-5/8" 27# casing scraper. Ran in well to 8405'. Backscuttled clean.

12-1 Rig shut down due to high winds.

12-2 Pulled out of well with bit and scraper. Ran in well with bull plug, 2 seals, locator, ported sub and 8-5/8" 36# RTTS tool on 2-7/8" tubing. Ran in well to 8405'. Unable to set RTTS tool with seals in production packer. Tested annulus to 1500 psi. Leaked 100 psi in 2 minutes. Released packer.

12-3 Using wireline, ran casing collar log from 3100'-2100'. Located stage collar at 2918'. Made up Pengo casing patch on wireline. Set top of patch at 2907', bottom at 2929'. Ran 2-7/8" 6.5# N-80 EUE tubing string consisting of bull plugged Baker 2 seals, one joint 2-7/8" tubing, Otis 2.205" No-Go nipple, one joint 2-7/8" tubing, Otis 2-7/8" sliding sleeve (closed), one joint 2-7/8" tubing, BST gas lift mandrel with pump-out plug set at 2500 psi and 2-7/8" tubing to surface. Drifted and hydrotested to 5000 psi. Spaced out and landed with 10,000# on packer. Pulled 20,000# to check latch. Tested seals, packer and annulus to 1500 psi. Secured well.

12-4 Using wireline, opened sliding sleeve. Changed over from 63#/cu.ft. polymer completion fluid to 3% KCl water. Set back pressure valve in doughnut. Removed BOPE and installed xmas tree. Tested xmas tree to 5000 psi with oil for 20 minutes. Removed back pressure valve. Released rig at 3:00 p.m.

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION

No. T 286-239

DIVISION OF OIL AND GAS

Report on Operations

R. M. Morrow, Agent
SOUTHERN CALIF. GAS CO.
810 S. Flower St.
Los Angeles, CA 90051

Ventura Calif.
Dec. 1, 1986

Your operations at well IW 77, API No. 037-21323, Sec. 28, T. 3N R. 16W, S.B. B.& M. Aliso Canyon Field, in Ventura County, were witnessed on 11/24/86. Bill Winkler, representative of the supervisor, was present from 1630 to 2000. There were also present Drilling Engineer

Present condition of well: 13 3/8" cem 900' 8 5/8" cem 7650', pc 2995', csg. patch 2878'-2910' & 2918'-2960'; 6 5/8" cem 7523' to 9025', perf 8515' & 8515' WSO, perf at intervals 8532' to 8734'.

The operations were performed for the purpose of Testing the blowout prevention equipment and installation.

DECISION:

THE BLOWOUT PREVENTION EQUIPMENT AND ITS INSTALLATION ON THE 8 5/8" CASING ARE APPROVED.

Note: Deficiency-Failed & Corrected, Choke Value Failed.

mep

M. G. MEFFERD

Michael Stettner

Murray W. Dosch

Ex. I - 39

Due to the large file size, this exhibit is an excerpt. The native file of this document is available upon request.

FORM 103

SUBMIT IN DUPLICATE

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION

DIVISION OF OIL AND GAS

DIVISION OF OIL AND GAS
RECEIVED
OCT 19 1979
SANTA PAULA, CALIFORNIA

History of Oil or Gas Well

OPERATOR SOUTHERN CALIFORNIA GAS COMPANY FIELD ALISO

Well No. I.W. #82, Sec. 27, T. 3N, R. 16W, S.B. B. & M.

Date 10/24/78, 19 Signed PSM/ P.S. Magruder, Jr.

P.O. Box 3249 Terminal Annex
Los Angeles, California 90051 Title Agent

(Address) (Telephone Number) (President, Secretary or Agent)

It is of the greatest importance to have a complete history of the well. Use this form to report a full account of all important operations during the drilling and testing of the well or during re-drilling, altering of casing, plugging, or abandonment with the dates thereof. Be sure to include such items as hole size, formation test details, amounts of cement used, top and bottom of plugs, perforation details, sidetracked junk, bailing tests, shooting and initial production data.

MWO 99530

Date	
1978	History of Well I.W. #82 - Aliso
7-25	Killed well with 450 barrels of 86#/cu.ft. brine-polymer drilling fluid.
8-9	Moved in California Production Service Rig #D-4. Started rigging up.
8-10	Finished rigging up. Removed Xmas tree and installed B.O.P.E. Tested blind rams and pipe rams to 4000 psi with water and nitrogen for 20 minutes each test. Tested Hydril "GK" to 3000 psi with water and nitrogen for 20 minutes. Released tubing from packer. Attempted to circulate well. Required 188 barrels to fill well. Unable to maintain circulation. Well was taking fluid at a rate of 100 barrels per hour.
8-11	Pumped in 90 sec. viscosity pill to establish circulation. Let pill stand at bottom of well for two hours. Pulled up 12 stands of tubing and attempted to circulate. Unable to maintain circulation and lost 32 barrels to well. Ran 12 stands back in well and pumped in 150 sec. viscosity pill (8 sacks carbonates and 2 sacks HEC polymer).
8-12	Established circulation. Circulated well. Pulled tubing out of well. Picked up Kelly and picked up fishing tools to recover GO-International casing patch. Did not recover patch.
8-13	Rig and crew idle.
8-14	Attempted to recover top section of 8 5/8" casing patch at 3967'. Set spear at 4002' but unable to jar patch loose.
8-15	Ran 5 3/4" spear to 3967' and engaged top of casing patch. When pulling out of well, one stand (60') of 2 7/8" tubing and fishing tools were dropped into well. Unable to run full gauge tools through casing head area, possibly because of junk in wellhead. Made several unsuccessful attempt to run 7 1/4" Johnston Bridge Plug.

8-16 Ran Lynes bridge plug and set at 100'. Dumped two sacks of sand on bridge plug. Removed B.O.P.E. and tubing head. Using Alco casing jacks and spear, removed 40' casing patch from well leaving bottom seals in well. Reinstalled B.O.P.E.

8-17 Reamed 7 13/16" O.D. tapered mill through tight spot in 8 5/8" casing at 14'. Ran in with Lynes retrieving head and circulated sand out. Recovered Lynes packer. Ran Johnston bridge plug and set at 510'. Pressure tested 8 5/8" casing from 510' to surface with 3000 psi for one hour - test O.K. Ran in well with 6 5/8" guide and overshot. Engaged fish at 7086' and pulled to 3989'. Jarred fish through bad spot in casing.

8-18 Laid down fish and fishing tools. Ran in well with Otis seal plug on latch-in locator and set in Otis packer at 7166'. Pulled up 20,000# to check latch. Spotted 10 sacks sand on top of Otis packer at 7166'. Waited one hour. Located sand at 7169'.

8-19 Spotted 10 sacks of sand on top of packer at 7166'. Ran in with 7 13/16" tapered mill and milled from 3990' to 3997'. Circulated well clean. Pulled out of well. Picked up 4 3/4" O.D. jars.

8-20 Rig and crew idle.

8-21 Ran in well with 7 13/16" tapered mill. Reamed from 4038' to 4039'. Ran to 4075' and circulated well clean. Continued running in well. Reamed past tight spot at 5372'. Ran in to 6098' and reamed to top of sand at 7112'. Pulled out of well. Rigged up Welex and shot four 1/2" holes at 7090'. Made up Johnston positrieve squeeze tool with 250' of 2 7/8" tubing stinger below squeeze tool and started running into well.

8-22 Ran in well to 7113'. Spotted 50 cu.ft. of fresh water and established breakdown of 10 cu.ft./minute at 1750 psi. Backscuttled water out. With open-end tubing hung at 7091' and Johnston positrieve squeeze tool at 6841', Dowell mixed and pumped 50 cu.ft. of Neat Class "G" cement with 30 cu.ft. of water ahead, 4 cu.ft. of water behind and 222 cu.ft. of mud to equalize. Pulled 5 stands and backscuttled 22 cu.ft. of excess cement out of well. Cement in place at 11:25 A.M. Set Johnston squeeze tool at 6540' and squeezed away 7.5 cu.ft. of cement at a final pressure of 2500 psi. Held pressure for two hours. Bled off pressure and pulled out of well. Broke off and laid down Johnston squeeze tool. Made up 7 5/8" bit and scraper with 4 drill collars on tubing and ran in well. Tagged soft cement at 6983'. Drilled out from 6983' to 7080'. Circulated well clean.

8-23 Drilled and cleaned out cement from 7080' to 7110'. Circulated well. Pulled out of well and laid down bit and scraper. Made up Johnston positrieve squeeze tool with 250' of 2 7/8" tubing tail on bottom and ran in to 5204'. Set squeeze tool and pressure tested holes at 7090'. Pressure bled from 2500 psi to 1500 psi at a rate of 2 cu.ft. per minute. Ran in to 7091' and set squeeze tool. Obtained breakdown at 2200 psi at a rate of 3 cu.ft. per minute.

8-24 With open-end tubing hung at 7091' and Johnston positrieve squeeze tool at 6841', Dowell mixed and pumped 50 cu.ft. of Neat Class "G" cement with 30 cu.ft. of water ahead, 4 cu.ft. of water behind and 215 cu.ft. of mud to equalize. Pulled 5 stands and backscuttled 20 cu.ft. of excess cement out of well. Cement in place at 7:15 A.M. Set Johnston squeeze tool at 6540' and squeezed away 9 cu.ft. of cement at a final pressure of 2500 psi. Held pressure for four hours. Bled off pressure and pulled out of well. Laid down Johnston squeeze tool. Made up 7 5/8" bit and scraper with four drill collars on tubing and ran in well. Tagged cement at 6978'. Drilled out from 6978' to 7110'. Circulated well clean.

8-25 Pulled tubing out of well. Laid down bit and scraper. Made up Johnston positrieve squeeze tool and ran in to 4300'. Set tool and pressure tested casing. Pressure bled from 2500 psi to 2400 psi in 20 minutes. Pulled tubing and squeeze tool out of well. Rigged up Dresser Atlas and shot two 1/2" holes from 7088' to 7089'. (2 shots misfired). Made second run and shot four 1/2" holes from 7088' to 7089'. Made up squeeze tool and ran in to 7019'.

8-26 With open-ended tubing hanging at 7091' and Johnston positrieve squeeze tool at 6841', Dowell spotted 30 cu.ft. of fresh water and established breakdown of less than 1 cu.ft. per minute at 1900 psi. Backscuttled water out. Dowell mixed and pumped 50 cu.ft. of Neat Class "G" cement with 30 cu.ft. of water ahead, 4 cu.ft. of water behind and 215 cu.ft. of mud to equalize. Pulled 5 stands and backscuttled 36 cu.ft. of excess cement out of well. Cement in place at 9:30 A.M. Set Johnston squeeze tool at 6540' and squeezed away 2 cu.ft. of cement at a final pressure of 2500 psi. Held pressure for 4 hours. Bled off pressure and pulled out of well. Laid down squeeze tool. Made up 7 5/8" bit and scraper with four drill collars on tubing and ran in well. Tagged top of cement at 7094'.

8-27 Rig and crew idle.

8-28 Drilled out cement from 7094' to 7120'. Circulated well clean. Made up Johnston positrieve squeeze tool and ran into well. Set tool at 4300' and pressure tested casing. Pressure bled from 2500 psi to 2300 psi in two minutes. Ran tubing to 7090' and spotted 30 cu.ft. of water across perforations. Pressured up on casing. Casing held 2500 psi O.K. for 20 minutes. Continued pressure testing casing up hole. Isolated possible casing leak between 6014' and 6055'.

8-29 Rigged up Triangle and ran Noise Log. Recorded from 7110' to 3000'. Rigged up McCullough to run Casing Inspection and Caliper Logs. Recorded Caliper Log from 7086' to 3000'.

8-30 Rigged up McCullough to complete Caliper Log. Recorded from 3000' to surface. Ran McCullough Casing Inspection Log. Tool malfunctioned No log was obtained. Rigged up Triangle to verify accuracy of of previously run Noise Log. Results were inconclusive.

8-31 Rigged up McCullough and ran Casing Inspection Log. Recorded from 7080' to surface. Ran Triangle Noise Log. Recorded from 7080' to surface. Determined that gas movement behind casing had stopped. Made up Johnston positrieve squeeze tool and ran in well. Set squeeze tool at 6027' and pressure tested casing to 2000 psi. Casing held pressure. Continued pulling up and testing at 5' intervals. Found no leaks between 6027' and 5894'.

9-1 Picked up Johnston 8 5/8" bridge plug and ran in well on 2 7/8" tubing. Set bridge plug at 6998'. Spotted 10 sacks of sand on top of plug. Pulled tubing out of well. Picked up Johnston positrieve squeeze tool and ran into well. Tagged top of sand at 6970'. Set squeeze tool at 6967' and pressure tested bridge plug. Plug held 3000 psi for 20 minutes. Changed over from polymer fluid to lease water.

9-2 Set Johnston positrieve squeeze tool at 6000'. Tested 8 5/8" casing from 6000' to 6998' with 3000 psi for one hour. Test inconclusive. Made tests with packer set at 4000', 5407', 5997', 5710', 5586' and 5523' with inconclusive results. Will change positrieve squeeze tool.

9-3 Rig and crew idle.

9-4 (Labor Day) Rig and crew idle.

9-5 Laid down Johnston test tool. Ran Baker fullbore. Pressure tested 8 5/8" casing from 6998' to 4000' with 3000 psi for one hour - O.K. Tested from 3995' to surface with 3000 psi for one hour - O.K. Isolated leak in 8 5/8" casing at 3997'.

9-6 Removed B.O.P.E. and installed tubing head. Reinstalled B.O.P.E. Tested pipe rams and blind rams at 4000 psi for 20 minutes. Tested Hydril GK at 3000 psi for 20 minutes. Tests witnessed and approved by D.O.G. Tested flanges and seals on tubing head at 5000 psi. Made up Jonston retrieving head and started running in well.

9-7 Ran in with Johnston retrieving head. Located sand fill at 6970'. Cleaned out to 6998'. Pulled Johnston bridge plug from 6998'. Laid down bridge plug and retrieving tool. Made up Otis retrieving head and ran in to 7056'. Changed over from lease water to 83# per cu.ft. polymer drilling fluid. Cleaned out fill from 7056' to 7159'

9-8 Attempted to recover Otis packer plug. Unable to latch onto plug due to junk (remainder of casing patch seal) wedged inside retrieving tool. Made up new retrieving tool and ran back to top of plug. Latched onto plug and pulled out of packer. Circulated well to clear gas. Approximately 13 barrels were lost to formation. Spotted high viscosity pill (300 sec.) across production zone. Started pulling out of well.

9-9 Ran in well with sawtooth collar on 2 3/8" tubing and cleaned out fill from 7258' to 7333'. Circulated well clean.

9-10 Rig and crew idle.

9-11 Ran in with production tester and set packer at 7082' with tail to 7102'. Opened tool at 11:30 A.M. for 5 minute initial flow. Closed for three hour initial shut-in. Final flow 6 1/2hours with gas to surface at 6:30 P.M. Flowed gas 2 1/2 hours. Closed tool at 9:00 P.M. for final shut-in. Backscuttled well to clear tubing of gas.

9-12 Pulled Lynes tester. Pressure chart readings were as follows:

IH 3970 psi
FH 3920 psi
IF 2300 psi
FF 2240 psi
ISI 2900 psi
FSI 2930 psi

Ran 2 7/8" tubing with 200' 2 3/8" tubing on bottom and sawtooth collars. Cleaned out from 7299' to 7335'. Circulated gas-cut mud from well. Ran in with production Lynes tester #2 to 7102'.

9-13 Set Lynes production tester at 7083' with tail to 7103'. Opened tool at 7:08 A.M. Closed tool at 10:08 A.M. Closed tool for final shut-in at 7:08 P.M. Backscuttled tubing free of gas and secured well. (Final pressure 880 psi).

9-14 Pulled out with Lynes production tester, pressures as follows:

Hydrostatic	3950 psi
Initial Flow	2110 psi
Final Flow	2020 psi
Final Shut-in	2965 psi

Ran Noise Log and found no gas leakage. Ran 7 5/8" bit and 8 5/8" casing scraper to 4100'. Circulated well clean.

9-15 Set casing patch in 8 5/8" 36# casing at 4016' - top 3974' (42') over stage collar leak at 3997'. Laid down 4 3/4 drill collars, Kelly and swivel.

9-16 Ran Otis 2 7/8" annular flow safety system on 2 7/8" EUE 8rd tubing, removing collars, cleaning pins, applying Bker seal and hydrotesting each joint to 5000 psi for one minute test. Landed tubing with 10,000# on packer. Pulled 25,000 and checked latch. Tubing string weight 42,000#.

9-17 Rig and crew idle.

9-18 Removed B.O.P.E. and installed Xmas tree. Rigged up Associated Services test pumps and tested Xmas tree to 5000 psi. Circulated 82#/cu.ft. polymer drilling fluid out of well with lease salt water. Rigged up Archer Reed, ran in and pulled side-door choke. Set plug in NO-GO nipple and tested packer and seals to 2000 psi for 20 minutes. Pulled tubing plug. Started rigging down. RELEASED RIG at 10:00 P.M.

AA/emr

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION

No. T 278-266

DIVISION OF OIL AND GAS

Report on Operations

Mr. P. S. Haggruder, Jr., Agent
Southern Calif. Gas Co.
P.O. Box 54790 Terminal Annex
Los Angeles, CA 90054

Santa Paula, Calif.
Sept. 7, 1978

Your operations at well IW 82, API No. 037-21458, Sec. 34, T. 3N, R. 16W S.B. B.& M. Aliso Canyon Field, in Los Angeles County, were witnessed on 9/6/78. T.E. Adams, representative of the supervisor, was present from 1700 to 2000. There were also present J. Awalt, company foreman

Present condition of well: additions to the casing record since proposal dated 7/20/78: Perf. 7088-7089' (cem. off)

The operations were performed for the purpose of testing the blowout prevention equipment and installation.

DECISION:

THE BLOWOUT PREVENTION EQUIPMENT AND INSTALLATION ARE APPROVED.

b

M. G. MEFFERD
State Oil and Gas Supervisor

By John L. Hardoin
Deputy Supervisor
John L. Hardoin

Ex. I – 40

FORM 103

SUBMIT IN DUPLICATE

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION

△ OSP

DIVISION OF OIL AND GAS

History of Oil or Gas Well

OPERATOR SOUTHERN CALIFORNIA GAS COMPANY FIELD Aliso Canyon

Well No. I.W. #83 - A.P.I. No.037-21455, Sec. 28, T. 3N, R. 16W, S.B. B. & M.

Date July 27, 1978 Signed P. S. Magruder Jr.

P. S. Magruder, Jr.

P. O. Box 3249, Terminal Annex
Los Angeles, California Title Agent

(Address) (Telephone Number) (President, Secretary or Agent)

It is of the greatest importance to have a complete history of the well. Use this form to report a full account of all important operations during the drilling and testing of the well or during re-drilling, altering of casing, plugging, or abandonment with the dates thereof. Be sure to include such items as hole size, formation test details, amounts of cement used, top and bottom of plugs, perforation details, sidetracked junk, bailing tests, shooting and initial production data.

Date 1978	
6-16	Killed well with 610 barrels of 72#/cu.ft. polymer drilling fluid. Removed lateral lines.
6-17	Moved in California Production Service Rig #D-4 and riggued up.
6-18	Rig and crew idle.
6-19	Removed Xmas tree. Installed Class III 5000 psi B.O.P.E. Pressure tested with water and nitrogen, as follows: Blind rams to 4000 psi Pipe rams " 4000 psi Hydril bag " 3000 psi Above tests witnessed and approved by Division of Oil and Gas. Released tubing from packer.
6-20	Well took 50 barrels of drilling fluid overnight. Pulled tubing. Laid down safety system, production equipment and 2 3/8" tubing. Ran 7 5/8" bit with casing scraper to top of packer at 8803'. Circulated well.
6-21	Well took 40 barrels of drilling fluid overnight. Continued pulling out of well. Ran Otis retrieving tool and latched into Permatrieve packer at 8803'. Unable to release packer. Pulled out and removed Otis tool.
6-22	Ran jars and bumper sub above Otis retrieving tool. Engaged packer at 8803'. Tripped jars once. Pulled out of well with packer leaving all but one packing element from packer in well. Ran Otis plug which was set and tested in 6 5/8" packer at 9080'. Pulled above top of 6 5/8" 8802'.
6-23	Ran 2 7/8" tubing to 9048' and circulated well. Halliburton equalized 35 sacks

of sand inside 6 5/8" liner. Pulled out of well. Ran 7 5/8" bit and 8 5/8" 36# casing scraper to top of 6 5/8" liner at 8822'. Circulated well. Pulled above top of 6 5/8" liner at 8822'.

6-24 Pulled out of well. Welex shot four 1/2" holes from 8811' to 8812'. Started in well with open-end 2 7/8" tubing.

6-25 Rig and crew idle.

6-26 Ran in well to top of liner at 8822'. Worked through hanger but could not get below 8846'. Rigged up Dowell and equalized six (6) sacks of sand. Pulled up and waited two hours. Sand bridged at top of liner at 8822'. Backscuttled clean down to 8846'. Re-spotted sand at 8846'. Pulled two stands and located sand at 8820'. Rigged up Dowell - had breakdown of 3 cu.ft. per minute at 1500 psi. Hung tubing at 8818' and pumped 5 cu.ft. water. Mixed 50 cu.ft. of Class "G" cement with 1% D-65 and with 5 cu.ft. water behind and 275 cu.ft. drilling fluid. Pulled to 8398' and squeezed away 32 cu.ft. at 2500 psi.

6-27 Pulled out of well. Rigged up power swivel. Ran 7 5/8" bit on 172' of 4 3/4" drill collars. Drilled out cement from 8695' to 8818'.

6 Ran in well and cleaned out fill from 8805' to 8818'. Pulled out. Rigged up Triangle and ran Noise Log which indicated gas still leaking by shoe. Pressure tested holes at to 3000 psi but could not get breakdown.

6-29 Pulled out of well. Rigged up Welex and shot four 1/2" holes at 8811'. Ran in to 8815' with open-end tubing. Pumped in 50 cu.ft. water. Pumped 4 cu.ft. per minute at 2800 psi. Hung tubing at 8818' - pumped in 30 cu.ft. water, 25 sacks of Class "G" cement with 1% D-65 and 5 cu.ft. water behind. Pulled to 8507', squeezed 20 cu.ft. - held 2500 psi on cement for two hours.

6-30 Pulled out. Made up 7 5/8" bit and scraper. Ran in and located cement at 8735'. Drilled out cement to 8818'. Circulated well clean.

7-1 Ran in and located fill at 8803'. Backscuttled clean to 8818' and pulled out of well. Rigged up and ran Triangle Noise Log which indicated gas leakage had stopped. Ran in well with sawtooth collar on 2 7/8" tubing. Cleaned out sand from 8818' to 8819'. Tools stopped.

7-2 Rig and crew idle.

7-3 Pulled out of well with 2 7/8" tubing to 1400' and transmission failed

7-4 Rig and crew idle. (Holiday)

7-5 Pulled out of well. Made up 4 3/4" bit and 4 3/4" drill collar. Ran in well and cleaned out rubber at top of liner hanger at 8822'. Cleaned out sand down to packer at 9060'. Circulated clean.

7-6 Pulled out of well. Made up Otis retrieving tool. Ran in and pulled packer plug loose. Circulated gas cut mud. Pulled out and laid down Otis tools. Measured and picked up 12 joints of 2 3/8" C.S. Hydril tubing (396'). Ran in well - had to work through packer at 9066'. Ran in to 9424' - no fill.

7-7 Ran in well to bottom of liner at 9424'. Pulled out. Made up Lynes drill stem test tools. Ran in and tested all Lynes valves and 1 1/2" test lines.

7-8 Set tester at 8796' with tail to 8816'. Took initial flow and shut in. Opened tool at 8:00 A.M. - did not have enough pressure to flow well in withdrawal line and opened into Baker tank. Bled off drilling fluid and well pressure dropped to zero. Closed valve on Lynes head and pressure built up to 560 psi. Reopened to Baker tank and pressure bled to zero. Closed in and pressure built to 350 psi. Bled off small amount of gas and drilling fluid. Closed tool at 4:00 P.M. and backscuttled gas from tubing.

7 Rig and crew idle.

7-10 Bled off well. Pulled tester loose. Rigged up Triangle Noise Log. Ran from 8830' to 7800' indicating no gas leak.

7-11 Pulled out of well. Rigged up Welex and ran Otis Permatrieve packer and set same at 8800' with bottom at 8805'. Ran Pengo 8 5/8" casing patch and set top at 3936' and bottom at 3978' with stage collar at 3958'. Rigged down "GO".

7-12 Rigged up Hydrotest and tubing tongs. Hydrotested tubing in well. Tested each joint to 5000 psi. Changed collars, cleaned pins and applied Baker seal.

7-13 Finished hydrotesting in well. Loaded out power tongs and test tools. Unable to latch into packer at 8800'. Pulled 2 3/8" tubing and tools through packer. Ran back in but still unable to latch into packer. Pulling out slowly - collars hanging on bottom of casing patch at 3978'.

7-14 Finished pulling out of well. Broke off Otis seal assembly and latch-in. Replaced seals and latch-in. Ran back in well, hydrotesting to 5000 psi for one minute. Spaced out tubing and landed with 10,000# on packer. Pulled 25,000# over weight of tubing to check latch. Removed B.O.P.E. and installed Xmas tree.

7-15 Rigged up Associated Services test pumps and tested Xmas tree to 5000 psi. Circulated 72#/cu.ft. polymer drilling fluid out of well with salt water. Ran in and pulled separation sleeve. Set plug in NO-GO nipple and tested packer and seals to 1000 psi. Pulled tubing plug.
RELEASED RIG at 6:00 P.M. (7-15-78).

jp

Ex. I – 41

PORTER 47

DAILY DRILLING REPORT

3-29 Continued running tubing and 1" control line. Tested safety valve and control line through donut with 5000 psi for 45 minutes, OK. Landed tubing. Tore out BOPE and installed production head. Tested through test port with 4500 psi for 15 minutes, OK. Tested through unibolt against Shaffer donut plug with 4650 psi for 15 minutes, OK. Rigged up Otis wireline. Closed sliding sleeve at 6782'. Set No-Go plug at 8254'. Pressured tubing and set Otis hydraulic packers. Pulled No-Go plug. Tested top packer by pressuring annulus with 1140 psi for 15 minutes, OK. Opened sleeve at 6782'. Control line at 5000 psi for overnight test.

SEE SUPPLEMENT DATED 4-20-73

SEE SUPPLEMENT DATED 5-4-73

PORTER 47

DAILY DRILLING REPORT

3-23 No morning tour. Waiting on cement, continued running 4-1/8" bit and scraper, tagged cement at 7888' (60' high) drilled and cleaned hard cement 7888-8058' circulated from 8104' for one hour. Pressure tested from surface to 8126' with 1625 psi for 30 minutes, OK. Started out of hole with bit and scraper.

3-24 Continued pulling bit and scraper, ran retrieving tool and released bridge plug at 8126'. Ran in from 8126' to set bridge plug onbottom. Stopped at 8138'. Believe cement from squeeze at 8056' was pumped into liner below bridge plug through unsqueezed WSO holes at 8138'. Pulled bridge plug, ran 4-1/8" bit and 5" casing scraper. Tagged cement at 8138'. Drilled and cleaned out soft cement 8138-8200' and hard cement at 8283'. Drilled and cleaned out hard cement at 8297' to 8352'. All perforations cemented, circulated on bottom one hour. Started out of hole with bit and scraper.

3-26 Continued pulling bit and scraper. Rigged up Dresser-Atlas. Ran cement bond log 7900-8355', cement bond at top of S-4 questionable. Jet perforated four 1/2" holes at 8135'. Made up and ran Johnston tester and bridge plug in tandem, set bridge plug at 8158'. Pulled up and set test tool at 8062', tail to 8080'. Opened tool at 6:50 pm. Dead throughout one hour test. Pulled bridge plug and tester. Recovered 5' rise oily workover fluid, charts OK. WSO. Witnessed and approved by P. R. Wygle of the D.O.G.

3-27 Rigged up Dresser-Atlas jet perforated four 1/2" holes 8159-8189', 8200-8223', 8270-8276', 8330-8343'. Used 3-1/2" carriers and 11.0 gram charges. Made up and ran Baker Model "C" bridge plug and fullbore packer. Set bridge plug at 8242'. Pulled up and set fullbore packer at 8140'. Pumped into formation at rate of 0.8 barrels per minute at 2200 psi. Too tight for Halliburton Clay-Lok. Pulled bridge plug and fullbore.

3-28 Rigged up to run Otis packer, Page safety valve and 1" GST control line. Tested safety valve and control line connections with 4850 psi for 20 minutes, OK. Ran into 5623'. Tested control line and safety valve with 4975 psi for 30 minutes, OK.

PORTER 47

DAILY DRILLING REPORT

3-21 Installed BOPE on new tubing head. Used rig pump. Tested pipe rams and casing from surface to 6911' with 1650 psi for 15 minutes, OK. Made up Baker 5" fullbore packer and retrieved tool. Ran in and recovered bridge plug at 6911'. Reset bridge plug at 8126'. Pulled up and set fullbore at 8056'. Tested bridge plug and 5" casing at 8056-8126' with 1625 psi for 15 minutes, OK. Pulled up and set fullbore at 7486'. Tested 7486-8126', no good. Tested from surface to 7486' - inconclusive. Picked up 14' of pup joints to space out properly between collars. Set fullbore at 7816'. Tested 7816-8126', no good. Tested from surface to 7816' with 1700 psi for 15 minutes, OK. Set fullbore at 7943' and tested 7943'-8126', no good. Set full bore at 8007' and tested at 7008'-8126', no good. Set fullbore at 8038' and tested 8038-8126', no good. Tested from surface to 8038' with 1750 psi for 15 minutes, OK. Leak isolated between 8038-8056'; collar at 8052' with fullbore set at 8038'. Could not break down formation with 3100 psi surface pressure (approximately 6650 psi at hole). Collar leak indicated, with fullbore hanging at 8056'. Pumped in two sacks of sand. Pulled up and hung fullbore at 7864'. Rigged up Go-International Jet, perforated four 3/8" holes at 8056' using 1-11/16" bore tubing perforator. Set fullbore at 7864'. Could not break down formation with 3100 psi surface pressure.

NOTE: All measurements are to center of packing element. Add 5' to all figures for correlation with CBL/CCL.

3-22 With fullbore hanging at 8093' pumped in 500 gallons of 15% HCL. Pulled up and set fullbore at 7555'. Pressure tubing to 3000 psi and shut well in for 2-1/2 hours. Broke down holes at 8056' with 4000 psi. Took fluid at a rate of 8 cf/minute at 3500 psi. Hung fullbore at 8093' and backscuttled out acid. Pulled up and hung fullbore at 7864'. With 20 cf fresh water ahead, mixed and pumped 50 sacks Class "G" cement with 0.75% CFR-2. Displaced with 5 cf fresh water and 161 cf workover fluid. Closed tool and squeezed 49 cf cement to formation. Final pressure 3300 psi. Released pressure and had 2 cf bleed-back. Used Halliburton equipment. Pulled fullbore packer. Started in hole with 4-1/8" bit and 5" casing scraper.

PORTER 47

DAILY DRILLING REPORT

3-13-73 Filled hole. Took one barrel. Circulated out fill from 8345' to 8357'. Turn on junk at 8357'. Circulated on bottom for 1-1/2 hours. Started out of hole. Rig broke down with bit and scraper at 7633'. Circulated 2 hours from 7633' waiting on engine.

3-14 Replaced rig engine.

3-15 Filled hole; took one barrel. Circulated one hour from 7633'. Pulled bit and scraper. Rigged up Dresser-Atlas. Ran cement bond log 6700-8354', Neutron Lifetime gama ray log 7780-8352' and Densi-Log 7800-8351'. Start in hole with 7" casing scraper.

3-16 Filled hole. Took one barrel. Continued running 7" casing scraper. Tagged top of liner at 6887'. Started out of hole. Discovered cracked brake flange on rig. Shut down for repairs with scraper at 1532'.

3-17 Pulled 7" scraper from 1532'. Made one 5" Baker Model "C" bridge plug at 1233'. 2-3/8" tubing below 7" Baker fullbore packer. Ran in and set in bridge plug at 8122' with fullbore hanging 6833', tail to 8075'. Tested from surface to 2811' with 1500 psi. No good. Set full bore at 6833' to 8122' with 1500 psi. No good. Tested on surface to 6833' with 1700 psi for 15 minutes. OK. Dropped down to retrieve bridge plug. Discovered that bridge plug as not set properly. Reset same at 8122'. Reset fullbore at 6833', tail to 8075'. Tested 6833' to 8122' with 1700 psi. No good. Retrieved bridge plug and set same at 6911'. Set fullbore at 5609', tail to 6851' and tested 5609-6911' with 1700 psi for 15 minutes, OK. Splice OK. Pulled bore and set same at 3525', tail to 4767'. Tested from surface to 3525' with 2150 psi for 15 minutes, OK. Pulled fullbore and set same at 2505' tail to 3747'. Tested from surface to 2505' with 3200 psi for 15 minutes, OK. Pulled full bore packer. Test summary 7" casing, OK. mid 5"x7", splice OK. Leak in 5" liner between 6911-8122'.

3-19 Filled 7"x 13-3/8" annulus. Took 45 barrels. Tore out BOPE and tubing heads. Rigged up spear in casing jacks. Could not unland 7" casing. Cut off casing head. Found 184,000# on casing. Welded extension on 7" casing.

3-20 X-rayed 7" weld, OK. Cut off base plug and welded on new casing head. X-rayed casing head weld, OK. Relanded 7" casing with 185,000#. Installed new tubing head. Tested primary fill with 3275 psi for 15 minutes, OK. Tested secondary fill with 3300 psi for 15 minutes, OK.

Ex. I – 42

(ALISO COPY)

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION
DIVISION OF OIL, GAS, AND GEOTHERMAL RESOURCES

HISTORY OF OIL OR GAS WELL

Operator: Southern California Gas Company
Field: Aliso Canyon
County: Los Angeles
Well: Frew 3
Surface Location: Sec 29 3N 16W S.B.B.M.
A.P.I. No. 03700666
Todd Van de Putte
Title: Senior Storage Field...
(President, Secretary, or Agent)

Date: 10/31/2013
Signature: Todd R Van de Putte
~~(Person Submitting Report)~~

Address: PO Box 2300, SC9365, Chatsworth, CA, 91313-2300
Telephone Number: 818-701-3339

History must be complete in all detail. Use this form to report all operations during drilling and testing of the well or during redrilling or altering the casing, plugging, or abandonment, with the dates thereof. Include such items as hole size, formation test details, amounts of cement used, top and bottom of plugs, perforation details, sidetracked junk, bailing tests, and initial production data.

Start Date	Ops. DOGGR Rpt
5/22/2013	Opened the well with 2000 psig surface pressure on the tubing. Rigged up and pumped 50 bbl of hi-vis HEC polymer and displaced with 66 bbls of 8.6 ppg KCl brine. Filled the well per schedule with 78 bbl of 8.6 ppg KCl brine. Installed the back pressure plug and nippled down the production tree. Nippled up and function tested the Class III 5M BOPE and secured the well.
5/23/2013	Rigged up the WEA test pump truck. Pressure tested the blind rams to 300 psig (low) and 5000 psig (high) for twenty minutes. Pressure tested the pipe rams to 300 psig (low) and 5000 psig (high) for twenty minutes. Pressure tested the Hydril annular preventer to 300 psig (low) and 3600 psig (high) for twenty minutes. Pressure tested the choke manifold and all the control valves to 300 psig (low) and 5000 psig (high) for twenty minutes (All BOPE equipment tested good). Rigged down and moved out the BOPE testing equipment. Rigged up the working floor, the tubing equipment, cleaned the location and secured the well.
5/28/2013	Filled the well with 33 bbl of 8.6 ppg KCl brine. Circulated the well and changed pipe rams from 2-7/8" to 3-1/2" . Unlanded the tubing and worked the completion tubing free from the permanent packer at 7630'. Pulled out of the well and laid down the 3-1/2" tubing and the SSSV control line. Laid down the 3-1/2" SSSV, 150 joints of 3-1/2" tubing and secured the well.
5/29/2013	Filled the well with 23 bbl of KCl brine. Pulled out of the well and laid down the 3-1/2" tubing and the production equipment. Changed the pipe rams from 3-1/2" to 2-7/8". Measured and picked up a 5-1/2" casing scraper and bumper sub on 2-7/8" tubing. Measured and picked up 2-7/8" tubing to 3200' and secured the well.
5/30/2013	Filled the well with 28 bbl of 8.6 ppg KCl brine. Measured and picked up 2-7/8" tubing to 7550' and tagged a tight spot. Worked through the tight spot at 7550' (could not clean up). Ran in the well to 7630' and rigged up and reverse circulated 70 bbl of KCl brine. Pulled out of the well to a kill string at 2900' and secured the well.
5/31/2013	Topped off the well with 30 bbl of 8.6 ppg KCl brine. Pulled out of the well and laid down the 5-1/2" casing scraper and the bumper sub. Nippled up a shooting flange with a packoff and rigged up the Schlumberger wireline unit. Made up the USIT tools and ran in the well. Tagged the permanent packer at 7630' and ran USIT log to 3400' in the 5-1/2" innerstring (Lost signal could not log.) Pulled out of the well and rigged down the wireline unit. Nippled down the shooting flange/packoff. Ran in the well to 3000' with a kill string and secured the well.
6/3/2013	Filled the well with 36 bbl of 8.6 ppg KCl brine. Pulled out of the well with the kill string. Made up a 4-5/8" string mill on 2-7/8" tubing and ran in the well to 7545'. Nippled up the PGSR and picked up the power swivel. Milled from 7545' to 7550' (Lost torque and pump pressure) Laid down the power swivel, pulled out of the well to 5800' and secured the well.
6/4/2013	Filled the well with 35 bbl of 8.6 ppg KCl brine. Pulled out of the well (left 4.6" string mill and bit sub in the well). Made up a 4.625" over shot with 3.75" grapple and a bumper sub on 2-7/8" tubing. Ran in the well to 7533' (Tagged 11' high) and attempted to work over the fish. Pulled out of the well and laid down the overshot. Ran in the well with a kill string to 2800' and secured the well.
6/5/2013	The well required 26 bbl of 8.6 ppg KCl brine to fill. Ran in the well to 7533'. Rigged up and pumped 20 gallons diesel and displaced with 43 bbl of KCl brine. Pulled out of the well. Made up a 1-1/8" spear with a 1.277" grapple and a bumper sub on 2-7/8" tubing. Ran in the well to 7533' and engaged the fish. Pulled free at 12K lb over the string weight. Pulled out of the well to 5300' and secured the well.
6/6/2013	The well required 25 bbl of 8.6 KCl brine to fill. Pulled out of the well and laid down the fish (recovered the mill and the bumper sub.) Made up a 4.25" mill and (2) 3-1/8" drill collars on 2-7/8" tubing. Ran in the well to the tight spot at 7539'. Rigged up the power swivel and PGSR and cleaned the tight spot area to 7546'. Ran in the well to the permanent packer at 7630' and laid down the power swivel and PGSR. Pulled out of the well to 5300' and secured the well.
6/7/2013	Filled the well with 27 bbl of 8.6 ppg KCl brine. Pulled out of the well and laid down the 4.25" mill and made up a new 4.5" mill. Ran in the well to 7539', rigged up the power swivel and PGSR. Cleaned out the tight spot in the 5-1/2" innerstring from 7539' to 7546' and ran in the well to the top of the permanent packer at 7630'. Rigged down the power swivel and nippled down the PGSR. Pulled out of the well to 6700' and secured the well.
6/10/2013	Filled the well with 30 bbl of 8.6 ppg KCl brine. Pulled out of the well and laid down (2) 3-1/2" drill collars and the 4.5" mill. Measured and picked up (14) joints of 1" P-110 tubing tail on 2-7/8" tubing and ran in well to 8001' (TD at 8020', 19' of fill). Nippled up the PGSR and circulated out fill to 8008' (Hard fill could not clean out). Circulated the well clean and pulled out of the well to 7600'. Nippled down the PGSR and secured the well.

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County: Los Angeles
Well: Frew 3
Surface Location: Sec 29 3N 16W S.B.B.M.
A.P.I. No. 03700666
Todd Van de Putte
Title: Senior Storage Field...
(President, Secretary, or Agent)

Date: 10/31/2013
Signature: Todd R Van de Putte
(Person Submitting Report)

Address: PO Box 2300, SC9365, Chatsworth, CA, 91313-2300
Telephone Number: 818-701-3339

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Start Date	Ops. DOGGR Rpt
6/11/2013	The well required 30 bbl of 8.6 ppg KCl brine to fill. Pulled out of the well with wet tubing (found plugged tubing). Laid down (14) joints of 1" tubing and changed out the tubing equipment. Made up a WEA 5-1/2" lok-set bridge plug on 2-7/8" tubing. Ran in the well rabbiting tubing and found more asphaltines in the tubing. Ran in the well to 7200' and secured the well.
6/12/2013	Filled the well with 25 bbl of 8.6 ppg of KCl brine. Ran in the well with the 5-1/2" bridge plug to 7624', set the bridge plug and filled the well. Pressure tested the annulus to 500 psig (bled to 0 psig). Released the bridge plug and pulled to 7616', pressure tested to 500 psig (opened the 5-1/2" x 7" inner string annulus and circulating through the annulus). Released the bridge plug and pulled to 7490' (40' above bad spot). Set the bridge plug and pressure tested to 500 psig (held pressure). Released the bridge plug and ran in the well to 7624', set the bridge plug, and filled the 5-1/2" annulus. Pumped into the 7"X 5-1/2" annulus at 1 bpm with 300 psig. Released the bridge plug, pulled out of the well and laid down the bridge plug. Ran in the well to 2800' with a kill string and secured the well.
6/13/2013	The well required 25 bbl of 8.6 ppg KCl brine to fill. Pulled out of the well with the kill string. Made up a Baker seal assembly with latch, 6' , 2-7/8" pup joint, XN nipple with PXN plug in place, 4', 2-7/8" pup joint, WEA on/off tool on 2-7/8" tubing. Ran in the well to the permanent packer at 7630', stabbed into packer and pulled 10,000lb over string weight to check the latch. Released from the on/off tool and filled the well. Pressure tested the annulus to 500 psig (Bled down to 0 psig in two minutes). Pulled out of the well to a kill string at 2800' and secured the well.
6/14/2013	The well required 17 bbl of 8.6 ppg KCl brine to fill. Pulled out of the well and laid down the top half of the on/off tool. Ran in the well with a kill string to 2800' and secured the well.
6/17/2013	Cleaned the location and perform misc site work as directed.
6/18/2013	The well required 24 bbl of 8.6 ppg KCl brine to fill. Pulled out of the well with the kill string. Rigged down the tubing equipment and the working floor. Nippled down the BOPE and nippled down the tubing head (sent in for repairs). Pulled the primary seals and made up a 5-1/2" casing spear. Unlanded the 5-1/2" inner string, stacked out the innerstring and released the spear. Nippled up a cross over flange and nippled up the Class III 5M BOPE. Rigged up the working floor and the tubing equipment. Made up the top half of the on/off tool with a perforated sub on 2-7/8" tubing. Ran in the well to 3000' and secured the well.
6/19/2013	The well required 14 bbl of 8.6 ppg KCl brine to fill. Ran in the well to the on/off tool at 7630'. Released from the packer and circulated well with 200 bbl of KCl brine. Pulled out of the well to 7500' (Rig down for repairs to replace or repair traveling block) and secured the well.
6/24/2013	The well required 50 bbl of 8.6 ppg KCl brine to fill. Pulled out of the well with packer seals. Made up a 4-3/4" drill collar and a spear and engaged the 5-1/2" innerstring casing. Attempted to release from the seals at 7650' (no movement). Rigged up theTiger wireline unit and made up a 5-1/2" chemical cutter. Ran in the well to 7590', correlated and attempted to cut the 5-1/2" innerstring casing at 7580' (Casing did not cut). Worked the pipe, released the spear and secured the well.
6/25/2013	The well required 24 bbl of 8.6 ppg KCl brine to fill. Rigged up the Tiger wireline unit and made up the free point indication tools through the spear. Ran in the well to 2000' pulled up 140,000 lb then up to 180,000 lb (The 5-1/2" innerstring casing pulled free). Rigged down the Tiger wireline unit and rigged up the 5-1/2" casing tongs. Pulled out of the well and laid down/loaded the 5-1/2" innerstring casing (Laid down 111 joints of 5-1/2"). Secured the well.
6/26/2013	The well required 23 bbl of 8.6 ppg KCl brine to fill. Continued to lay down the 5-1/2" 20# N-80 inner string. Rigged down the 5-1/2" casing tongs and slips. Rigged up the tubing handling equipment. Moved out the 5-1/2" innerstring casing. Made up a 4" spear, a 4.805" grapple, 4.75" jars, (2) 4.75" drill collars, 4.75" accellerator, and a 4.75" bumper sub on the 2-7/8" L-80 work string. Ran in the well with the spear and BHA and secured the well. Spear at 7260' (279' above ETOF @ 7539').
6/27/2013	Filled the well with 24 bbl with 8.6 ppg KCl brine. Ran in the well with a 4" spear, 4.805" grapple, 4.50' extension, 6" stop, 4.75" jars, (2) 4.75" drill collars, 4.75" accelerator, and a 4.75" bumper sub on 2-7/8" L-80 work string. The 6" stop ring would not pass 7493'. Pulled free with 20k lb over string weight. Pulled out of the well and laid down the 6" stop ring. Picked up the previous BHA with a 5.5" stop ring and ran in the hole, engaged top of 5-1/2" 20# innerstring at 7539'. Jarred for 10' with 50k lb over string weight then pulled free. Continued to pull out of the well with 1000 lb over string weight. Pulled up the hole to 6490' and secured the well.

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Start Date	Ops. DOGGR Rpt
6/28/2013	Filled the well with 24 bbl of 8.6 ppg KCl brine. Pulled out of the well and laid down the BHA (No casing recovery, spear slipped off). Ran in the well with a kill string to 2817', secured the rig and the well.
7/1/2013	Filled the well with 30 bbl of 8.6 ppg KCl brine. Pulled out of the hole with the kill string. Made up a 4.75" taper mill and a bumper sub on 2-7/8" tubing. Ran in the well to 7531'. Picked up a power swivel and milled 5.5" from 7531' to 7539'. Pulled out of the well to a kill string at 2970' and secured the well.
7/2/2013	The well required 10 bbl of KCl brine to fill. Pulled out of the well with the kill string and laid down the 5.5" mill. Made up a spear with a 4.805" grapple, 12' extension, bumper sub, jars, (2) 4-2/3" drill collars and an accelerator on 2-7/8" tubing and ran in the well to a kill string at 2800' and secured the well. Opened the well and ran into the top of 5-1/2" innerstring at 7531'. Engaged the innerstring and jarred at 80,000 lb to 120,000 lb for 50' and pulled out of the well to 5700' (at 10,000 lb over string weight) and secured the well.
7/3/2013	Filled the well with 4 bbl of KCl brine. Pulled out of the well and laid down the fishing tools (no recovery.) Made up a spear with a 4.08" grapple, bumper sub, jars, (2) 4-3/4" drill collars and an acceleator on 2-7/8" tubing. Ran in the well to 7539', engaged the 5-1/2" innerstring and jarred loose. Pulled out of the well, stood back the fishing tools and laid down 46' of 5-1/2" innerstring casing). Ran in the well to 2800' with a kill string and secured the well.
7/8/2013	Filled the well with 10 bbl of 8.6 ppg KCl brine. Pulled out of the well with the kill string. Made up 2-7/8" saw-tooth collar ran in the well to the cut at 7580'. Nippled up the PGSR and made up a swivel. Worked on the fish and cleaned out to the packer at 7650' (asphaltines in returns). Reverse circulated the well clean and nippled down the PGSR. Pulled out of the well to a kill string at 2800' and secured the well.
7/9/2013	Repaired the rig. Filled the well with 30 bbl of 8.6 ppg KCl brine. Pulled out of the well with the kill string. Made up a 5-1/2" hydraulic casing cutter with 4-1/2" stabilizer on 2-7/8" tubing. Ran in the well to 7580', worked into the stub and tagged the packer at 7630'. Nippled up the PGSR and picked up the power swivel. Pulled to 7640', opened the casing cutter and attempted to cut (No torque at the tool). Nippled down the PGSR and the power swivel. Pulled out of well to 6400' and secured the well.
7/10/2013	Filled well with 29 bbl of 8.6 ppg KCl brine. Pulled out of the well with the kill string and laid down the casing cutter (found cutter had malfunctioned knives did not open.) Made up a 3-5/8" hydraulic cutter with stabilizer on 2-7/8" tubing. Ran in the well to 7580', worked into the stub. Nippled up the PGSR and the power swivel. Ran in the well to 7620', opened the casing cutter and cut the 5-1/2" casing (200 psig pressure drop and lost torque). Nippled down the PGSR and the power swivel. Pulled out of the well to 6000' and secured the well.
7/11/2013	The well was standing full of KCl brine. Pulled out of the well and laid down the 5-1/2" casing cutter. Made up a spear with 4.695" grapple, 6' extension, 5" stop, bumper sub, jars (1) joint 3-1/2" drill pipe, (2) 4-3/4" drill collars, and an accelerator on 2-7/8" tubing. Ran in the well to top of the 5-1/2" casing stub at 7580', engaged the casing, jarred on the 5-1/2"casing at 80,000 lb and jarred free. Pulled to 7545' and jarred on the 5-1/2" casing (Pulled out of the casing stub), re-engaged the casing stub and jarred on the 5-1/2" casing. (pulled out of the casing stub). Re-engaged the casing stub, jarred, and pulled out of the casing stub. Pulled out of the well to 2800' and secured the well.
7/12/2013	Filled the well with 24 bbl of 8.6 ppg KCl brine. Pulled out of the well and laid down the fishing tools (No casing recovery). Made up a spear with a 4.805" grapple, 6' extension, 5" stop, bumper sub, jars, (1) joint 3-1/2" drill pipe, (2) 4-3/4" drill collars, and an accelerator on 2-7/8" tubing. Ran in the well to the top of the 5-1/2" casing stub at 7580', engaged the casing stub and jarred free. Pulled out of the well and laid down the fishing tools and 45' of 5-1/2" casing . Made up a 4-1/2" string mill on 2-7/8" tubing. Ran in the well to a kill string at 2800' and secured the well.
7/15/2013	The well required 7 bbl of 8.6 ppg KCl brine to fill. Ran in the well to the top of the 5-1/2" casing stub at 7624', nippled up the PGSR and the power swivel. Reamed through the top of the 5-1/2" casing stub and cleaned out fill to the permanent packer at 7630'. Reverse circulated the well clean, nippled down the PGSR and the power swivel. Pulled out of the well to a kill string at 2800'. Shut down the rig for repairs and secured the well.

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Start Date	Ops. DOGGR Rpt
7/16/2013	The well required 2 bbl of KCl brine to fill. Pulled out of the well with the mill and laid down the BHA/ tools. Made up a spear with a 4.408" grapple, 5' extension, bumper sub, jars, (1) joint 3-1/2" drill pipe, (2) 4-3/4" drill collars and an accelerator on 2-7/8" tubing. Ran in the well to the top of the 5-1/2" casing stub at 7605' and attempted to work through a tight spot. Rigged up and attempted to circulate down. Pulled out of the well and laid down the BHA/tools. Made up a spear, an extension, bumper sub, jars, (3) joints 3-1/2" drill pipe,(1) 4-3/4" drill collar and an accelerator on 2-7/8" tubing. Ran in the well to 2800' and secured the well.
7/17/2013	Filled the well with 2 bbl of 8.6 ppg KCl brine. Ran in the well to the top of the 5-1/2" casing stub at 7620', engaged the casing stub, and jarred loose. Pulled out of the well and laid down the BHA/fish (full recovery; 30' of 5-1/2" and the seal assembly). Laid down the drill pipe, drill collars and the fishing tools. Made up an 7" all weight casing scraper and bumper sub on 2-7/8" tubing. Ran in the well to 3500' and secured the well.
7/18/2013	The well required 22 bbl of 8.6 ppg KCl brine to fill. Ran in the well with the 7" casing scraper to 7495', worked down to 7543' and attempted to work down hole. (Could not go deeper.) Rigged up and reverse circulated the well clean for the USIT log. Pulled out of the well and laid down the 7" casing scraper. Ran in the well with a kill string to 2800' and secured the well.
7/19/2013	The well required 24 bbl of KCl brine to fill. Pulled out of the well with a kill string and nippled up the shooting flange for the USIT log. Rigged up the Schlumberger wireline unit and made up the USIT/Neutron tools. Ran in the well to 7650', logged the 7" production casing with the USIT/Neutron tools from 7650' to the surface. Rigged down and moved out the Schlumberger wireline unit and nippled down the shooting flange. Ran in the well with a kill string to 2800' and secured the well.
7/22/2013	The well required 24 bbl of 8.6 ppg KCl brine to fill. Pulled out of the well with the kill string and nippled up the shooting flange. Move in and rigged up the Scientific Drilling wireline unit. Made up the Gyro survey tools and ran in the well with Gyro tools to 7650'. Logged from 7650' to the surface. Rigged down and moved out the Scientific Drilling wireline unit and nippled down the shooting flange. Ran in the well with a kill string to 2800' and secured the well.
7/23/2013	Loaded the drill collars, fishing tools and the excess 2-7/8" tubing. Filled the well with 25 bbl of 8.6 ppg KCl brine. Pulled out of the well with the kill string. Measured and picked up a 2-1/16" mule shoe and (15) joints of 2-1/16" CS hydril tubing on 2-7/8" tubing. Ran in the well and tagged fill at 7975'. Nippled up the PGSR and the power swivel and cleaned out fill to 8014'. Reverse circulated the well clean (bottom 9' of perfs covered). Pulled out of the well to 7525' and secured the well.
7/24/2013	Filled the well with 24 bbl of 8.6 ppg KCl brine. Ran in the well and tagged at 8014' (W. Beil DOGGR waived witness of tag). Circulated the well clean, pulled to 7500' and secured the well.
7/25/2013	The well required 25 bbl of 8.6 ppg KCl brine to fill. Ran in the well to 8014', rigged up and circulated well clean (W. Biel DOGGR verbal to place bottom cement plug). Rigged up the HES cementing equipment. Held safety meeting with the crews and pressure tested the lines and the equipment to 2000 psig. Mixed and pumped 16 bbls (50 sx) of 14.8 ppg Class "G" cement with additives and displaced with 41 bbl of KCl brine. Estimated top of cement at 7419'. Pulled out of the well to 7300', Rigged up and reverse circulated 80 bbl (2 cu. ft. cement returns to the surface). Pulled to 6900', secured the well and rigged down and moved out the HES cementing equipment.
7/26/2013	Filled the well with 36 bbl of 8.6 ppg KCl brine. Ran in the well and tagged the top of the plug cement at 7466' (47' low). Pulled out of the well and laid down (15) joints of 2-1/16" tubing. Ran in the well to 7464', spaced out the tubing for the cement plug and secured the well.
7/29/2013	Filled the well with 36 bbl of 8.6 ppg KCl brine. Moved in and rigged up the HES cementing equipment. Held a safety meeting with crews. The HES pump truck down for repairs, waited on repairs. The HES pump truck could not be repaired on the location; fuel pump out. Rigged down the HES pump truck and secured the well.
7/30/2013	Filled the well with 23 bbl of KCl brine. Rigged up the HES cementing equipment and held safety meeting with crews. Pressure tested the lines and equipment to 2500 psig. With the tubing tail at 7566', mixed and pumped 5 bbls fresh water ahead followed by 129 cuft (70 sacks) of 14.8 ppg Class "G" cement with additives and displaced with 39 bbls of KCl. Cement in place at 12:30. Pulled out of the well to 6846' and reverse circulated 80 bbl of KCl brine with approximately 3 cuft cement returns to the surface. Secured the well.

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION
DIVISION OF OIL, GAS, AND GEOTHERMAL RESOURCES

HISTORY OF OIL OR GAS WELL

Operator: Southern California Gas Company
Field: Aliso Canyon
County: Los Angeles
Well: Frew 3
Surface Location: Sec 29 3N 16W S.B.B.M.
A.P.I. No. 03700666
Todd Van de Putte
Title: Senior Storage Field...
(President, Secretary, or Agent)

Date: 10/31/2013
Signature: Todd R Van de Putte
(Person Submitting Report)

Address: PO Box 2300, SC9365, Chatsworth, CA, 91313-2300
Telephone Number: 818-701-3339

History must be complete in all detail. Use this form to report all operations during drilling and testing of the well or during redrilling or altering the casing, plugging, or abandonment, with the dates thereof. Include such items as hole size, formation test details, amounts of cement used, top and bottom of plugs, perforation details, sidetracked junk, bailing tests, and initial production data.

Start Date	Ops. DOGGR Rpt
7/31/2013	Filled the well with 25 bbl of 8.6 ppg KCl brine. Ran in the well to 6943' and tagged the cement plug (B. Hesson DOGGR waived witness of cement tag). Rigged up and pressure tested the 7" production casing (pumped in the well with 200 psig at 3 bpm). Pulled out of the well and made up a 7" test packer on 2-7/8" tubing. Ran in the well to 6840". Set the 7" test packer, pressure tested down to 1000 psig surface pressure for twenty minutes (held pressure). Released the test packer and pulled to 5650', set the test packer and pressure tested down to 1000 psig surface pressure for twenty minutes(held presure). Pulled to 5586', set the test packer and tested down to 1000 psig surface pressure for twenty minutes(held pressure). Pulled to 3492', set the test packer and pressure tested to 1000 psig surface pressure for twenty minutes (held pressure). Pulled to 3392', set the test packer and pressure tested to 1000 psig surface pressure for twenty minutes (held pressure). Pulled to 3209', set the test packer and pressure tested to 500 psig surface pressure for twenty minutes (held pressure). Pulled to 2204', set the test packer and pressure tested down pumped away at 200 psig at 3 bpm. Filled the annulus and re-tested to 1000 psig surface pressure for twenty minutes (held pressure). Ran in the well to 2706', set the test packer and pressure tested the annulus at 300 psig at 3 bpm. Released the test packer and secured the well.
8/1/2013	Filled the well with 16 bbl of 8.6 ppg KCl brine. Pulled out of the well and laid down the test packer. Ran in the well with 2-7/8" tubing to 6943'. Rigged up and pumped 53 bbl of 72 lb/cuft abandonment mud with the top of mud plug at 5600'. Pulled out of the well and rigged up Tiger wireline unit. Made up a 5" perforating gun with 4 - 0.5" hpf, 90 degrees phasing. Ran in the well, correlated and perforated from 5575' to 5580'. Rigged down and moved out the Tiger wireline unit. Made up a 7" test packer on 2-7/8" tubing and ran in the well to 3100' and secured the well.
8/2/2013	The well required 15 bbl of KCl brine to fill. Ran in the well with the 7" test packer to 5565', set the test packer and established perforation pump in rate at 2 bpm with 500 psig surface pressure. Pulled out of the well and laid down the 7" test packer. Made up a 7" cement retainer and ran in the well to 5565', set the retainer and released from the retainer. Stabbed into the 7" retainer and established a pump in rate at 2.5 bpm at 500 psig surface pressure and secured the well.
8/5/2013	Filled the well with 25 bbl of KCl brine. Rigged up the HES cementing equipment, held a safety meeting with the crew and pressure tested the cementing equipment and lines to 2500 psig. Stabbed into the 7" retainer at 5565', established a pump-in rate at 2.5 bpm at 500 psig. and unstabbed from the retainer. Mixed and pump 22.9 bbl (129 cuft/70 sacks) of 14.8 ppg Class "G" cement with additives and displaced with 9 bbl of KCl brine. Stabbed into the retainer and squeezed a total of129 cuft (Final squeeze pressure 390 psig @ 1.2 bpm). Unstabbed from the 7" retainer and reverse circulated with 70 bbl KCl brine with a trace of cement to surface. Rigged up the HES cementing equipment, mixed and pumped 9.6 bbl (30 sacks/ 54 cuft) of 14.8 ppg Class "G" cement with additives and displaced with 31 bbl of KCl brine. Pulled out of the well to 5300', rigged up and reverse circulated 60 bbl with 6 cuft of cement returns to the surface. Pulled out of the well to 5146', rigged down and moved out HES cementing equipment and secured the well. (E. Blevins DOGGR waived the witness of the cement squeeze and cement plug).
8/6/2013	Filled the well with 26 bbl of KCl brine. Ran in the well and tagged the cement plug at 5437' (E. Blevins waived and approved the witness of tag). Rigged up and pumped 79 bbl of 72 lb/cuft abandonment mud with the top of the mud plug at 3450'. Laid down the excess 2-7/8" tubing, pulled out of the well and laid down the stab in guide. Ran in the well to 3450'. Moved in and rigged up the HES cementing equipment, held a safety with the crews and pressure tested the equipment and lines to 1500 psig. With open ended tubing at 3450', mixed and pumped 22.5 bbl (126 cuft/ 70 sacks) of 14.8 ppg Class "G" cement with additives and displaced with 16 bbl of KCl brine. Pulled out of the well to 2860', rigged up and reverse circulated with 60 bbl of KCl brine (3 cuft of cement returns to the surface). Pulled to 2750' and secured the well.
8/7/2013	Filled the well with 15 bbl of KCl brine. Ran in the well to 2942', tagged the cement plug (E. Blevins DOGGR witnessed and approved cement tag). Pulled out of the well and laid down the excess 2-7/8" tubing. Pulled out of the well and laid down the stab in guide. Ran in the well with a WEA 7" test packer. The 7" 23# production casing tested good at 700 psig surface pressure from 2658' to the top of the cement at 2942' and from 2643' to the surface. Located holes in the 7" production casing and obtained an injection rate of 3 bpm at 200 psig between 2643' and 2658'. Pulled out of the well and laid down the 7" WEA test packer. (B. Hesson verbally approved mudding the hole from top of the cement at 2942' to the holes at 2658' as well as a cement plug from the holes at 2658' to +/- 1838'). Ran in the well open ended and spotted 11 bbl of 72 lb/cuftf abandonment mud in the 7" 23# production casing from 2942' to 2658' and secured the well.

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HISTORY OF OIL OR GAS WELL

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Field: Aliso Canyon
County: Los Angeles
Well: Frew 3
Surface Location: Sec 29 3N 16W S.B.B.M.
A.P.I. No. 03700666
Todd Van de Putte
Title: Senior Storage Field...
(President, Secretary, or Agent)

Date: 10/31/2013
Signature: Todd R Van de Putte
(Person Submitting Report)

Address: PO Box 2300, SC9365, Chatsworth, CA, 91313-2300
Telephone Number: 818-701-3339

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Start Date	Ops. DOGGR Rpt
8/8/2013	The well required 15 bbl of KCl brine to fill. Rigged up the HES cementing equipment and held a safety meeting with the crews. Pressure tested the lines and equipment to 2000 psig. With the 2-7/8" tubing tail at 2655', mixed and pumped 32.4 bbl (181 cuft/100 sacks) of 14.8 ppg Class "G" cement with additives and displaced with 10.6 bbl of KCl brine. (Estimated top of cement at 1838'). Pulled out of the well to 1753', rigged up and reverse circulated with 50 bbl of KCl brine (Trace of cement returns to the surface). Pulled to1600' and secured the well.
8/9/2013	The well required 30 bbl of KCl brine to fill. Ran in the well to 2658' (No cement) and attempted to pressure test the 7" production casing. Pumped at 2 bpm at 300 psig. Pulled out of the well to 1600', rigged up and reverse circulated and secured the well.
8/12/2013	Filled the well with 16 bbl of KCl brine. Ran in the well to 2658', rigged up the HES cementing equipment and held a safety meeting with the crews. With the 2-7/8" tubing tail at 2658', mixed and pumped 19.7 bbl (111 cuft/60 sacks) of 14.8 ppg Class "G" cement with flo-chek additives and displaced with 12 bbl of KCl brine. Estimated top of cement at 2155'. Pulled out of the well, cleared the tubing, ran in the well to 1813' and secured the well.
8/13/2013	Filled the well with 2 bbl of KCl brine. Ran in the well and tagged the cement at 2255' (W. Biel DOGGR witnessed and approved cement tag and mudding of well). Rigged up and pumped 57 bbls of 72 lb/cuft abandonment mud with the top at 810'. Pulled out of the well and laid down the excess 2-7/8" tubing. Made up a WEA 7" casing cutter, ran in the well to 900', rigged up the PGSR and the power swivel. Cut the 7" production casing at 900' and rigged down the power swivel. Pulled out of the well and laid down the casing cutting tools. Rigged down the working floor, nippled down Class III 5M BOPE and secured the well.
8/14/2013	Rigged up and cut the well head bolts and nippled down the tubing head. Made up a 7" spear, unlanded 7" production casing at 40,000 lb, removed the pack off and the slips. Rigged up the working floor and the WEA casing tongs. Pulled out of the well and laid down the 7" production casing (Laid down 20 jts, 889', KB 896'). Rigged down the 7" casing tongs and rigged up the tubing equipment. Made up a 13-3/8" casing scraper and a bumper sub on 2-7/8" tubing. Ran in the well to the top of the 7" production casing stub. Pulled out of the well and laid down the 13-3/8" casing scraper. Loaded tools, equipment and secured the well.
8/15/2013	Moved in and rigged up the Schlumberger wireline unit and held a safety meeting with the crews. Made up the 13-3/8" USIT/Neutron tools, ran in the well to 890' and logged to the surface. Rigged down and moved out the Schlumberger wireline unit. Made up a WEA 13-3/8" cement retainer and ran in the well to 555' and the retainer stopped. Pulled out of the well, laid down the 13-3/8" retainer and secured the well.
8/16/2013	Nippled up a Class II BOPE and cleaned the location.
8/19/2013	Opened the well with 0 psig surface pressure on the tubing and the casing. Filled the well with 1 bbl of KCl brine. Gas scoped the cellar and welded a 2" nipple on the casing head. Ran in the well to 889', rigged up and pressure tested the well to 200 psig surface pressure. Moved in and rigged up the HES cementing equipment and held safety meeting with the crews. Pressure tested the equipment and the lines to 2000 psig. Mixed and pumped 61 bbl (342 cuft/190 sacks) of 14.8 ppg Type III cement with additives and displaced with 2.5 bbl of KCl brine (Esitmated top of the cement at 500'). Pulled to 437', rigged up and reverse circulated out 18 bbl of cement. Pulled to 300', secured the well and cleaned the location.
8/20/2013	The well was standing full of KCl brine. Ran in the well to 514', tagged the cement (M. Davis DOGGR witnessed and approved cement tag and mudding of well.) Rigged up and pumped 23 bbl of 72 lb/cuft abandonment mud form 514' to 360'. Pulled out of the well and laid down the excess 2-7/8" tubing. Rigged down and moved out the working floor and the tubing equipment. Nippled down the Class II BOPE. Rigged up the working floor and tubing equipment. Ran in the well to 360', rigged up for a top job and secured the well.
8/21/2013	Spotted a vacuum truck. moved in and rigged up the HES cementing equipment and held a safety meeting with the crews. Pumped 2 bbl of water and pressure tested the equipment and the lines to 1000 psig. Mixed and pumped 62 bbl (348 cuft) of 14.8 ppg Type III cement with additives with full cement returns to the surface. (W. Beil DOGGR witnessed cementing of well). Laid down the 2-7/8" tubing and topped off the cement plug. Rigged down and moved out the HES cementing equipment. Cleaned the cellar, the cement bins and rigged down equipment.
8/22/2013	Ran in the well to 29' and tagged the cement plug. Rigged down the hoist and loaded the BOPE. Cleaned the mud pit and the Baker tanks.

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Surface Location: Sec 29 3N 16W S.B.B.M.
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Start Date	Ops. DOGGR Rpt
8/23/2013	Moved in and rigged up the HES cementing equipment and held a safety meeting with the crews. With the 2-7/8" tubing tail at 29', mixed and pumped 6 bbl (33 cuft/24 sacks) of 14.8 ppg Type III cement with additives with cement returns to the surface. Cleaned the cellar and moved equipment off of the location.
8/24/2013	Cleaned the location. Cut off the 13 3/8" casing head and cut the 13-3/8" surface casing to an elevation of 7' below ground level.
9/20/2013	Removed the cellar floor around the 13-3/8" surface casing.
9/25/2013	Met with Mark Davis (CADOGGR). Witnessed the surface cement plug. Verified no leaks. Welded the steel plate to the 13-3/8" surface casing stub with four 2" long welds around the circumference of the steel plate . Welded: "Frew 3 03700666 9-25 -2013 " on the plate.

Ex. I – 43

FREW 3
ALISO CANYON

Surface Casing:
13-3/8" 54.5# J-55
0' - 1055'

Inner-string:
5-1/2" 20# N-80
AB FL-4S
0' - 7650'

Production Casing:
7"
0' - 835' 23# N-80
835' - 4641' 23 # J-55
4641' - 6732' 23 # N-80
6732' - 7799' 26 # N-80

Hole in 7" casing at 3240'
(Sqzd with 147 cf cmt)

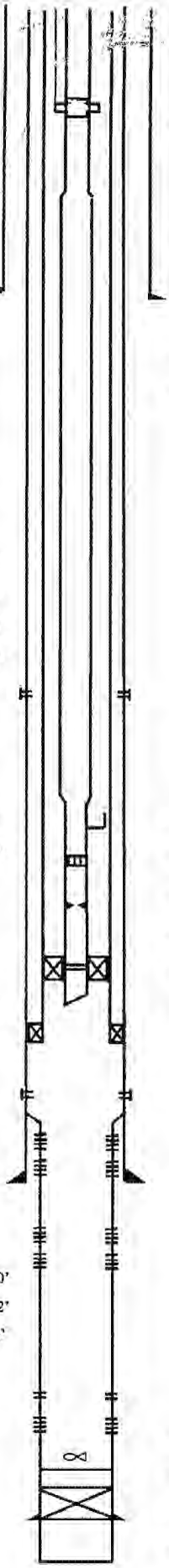
5-1/2" Baker Model F
packer at 7622' (pra 7630')

7" Otis Permatrieve
packer at 7650'

WSO holes at 7660' (sqzd)

Liner:
5" 18# J-55
7681' - 8102'

Perfs: 4 spf (1977)
7715' - 7730'
Perfs: 4 spf (1973)
7755' - 7758', 7766' - 7790'
7818' - 7836', 7840' - 7842'
7845' - 7846', 7850' - 7856'
7870' - 7880'
WSO holes at 7985'
Perfs: 2 spf (1963)
7992' - 8023'



489' Baker Model T5 SCSSV

Tubing
0' - 491' (2-7/8" 6.5# N80 8rd EUE)
491' - 7477' (3-1/2" 9.3# N80 8rd EUE)
7477' - 7620' (2-7/8" 6.5# N80 8rd EUE)
Note: 3-1/2" tubing collars turned down to 4.25" OD

7508' PSID-U GLM w/ 1.0" latch
7552' Otis XD Sliding Sleeve (2.313")
7589' Otis XN Nipple (2.313" bore, 2.205" nogo)
7620' 2-7/8" x 2-3/8" crossover (1.991" ID)
7622' Baker Model E latch and seal units (2)
7624' Baker guide shoe

Top of fish at 8020'
Top of cement plug at 8050'
Liner cemented at 8102'
TD at 8485'

Jim Dayton 11\19\94, DG Neville 5/8/95
W:\AC\FREW3\MEC_F3.PUB

Elevation (GRD):	2479' ASL
Elevation (KB):	2487' ASL
Elevation (KB):	8' AGL
Status:	Injection/Withdrawal
Flow Regime:	Tubing Flow
Surface Loc.:	535.5' S and 1275.1' W from station 84
Bottomhole Loc.:	At 7800' MD, wellbore is 36' N and 9' W of surface location.

9/21/44 - 3/30/45: Well drilled and completed.

11/5/63 - 11/23/63: Milled up liner and deepened well to 8485' from original TD of 8006'. Ran and cemented 5" liner at 8102'. Drilled out cement to 8050'.

5/1/73 - 5/22/73: Converted well to gas storage. Ran bit and scraper to 8003' and was unable to clean out further. Jet perforated at 4 spf various intervals in Sesnon zone.

9/8/77 - 9\20\77: Cleaned out to 8020'. Left a cone off 4-1/8" bit in well. Perforated 4 spf from 7715' to 7730'. Pressure tested casing and completed well with 2-7/8" tubing and an SSSV.

1/28/86 - 2/11/86: Ran internal caliper log and casing inspection log. Identified hole in casing at 3240'. Squeezed hole and pressure tested casing to 1000 psi. Ran 5-1/2" inner casing string and completed with 2-3/8" tubing.

10/28\94 - 11\3\94: Converted well from casing flow to tubing flow. Installed SCSSV and ran large diameter tubing string.

Well Volume

	Cu. Ft.	Bbl
Tubing	359	64
Innerstring	1187	212
Csg/Lnr	41	8
Total	1587	284

Zone Tops

MP	7283'	(7283')
S1	7582'	(7582')
S4	7676'	(7676')
S6	7718'	(7718')
S8	7760'	(7760')

	Reviewed By	Date
Drilling:	DG Neville	5/11/95
Petroleum:	R Patterson	5/11/95
Region:	Tom Wolfe	5/17/95

CONFIDENTIAL

Ex. I – 44

9-15-90 Woods
Day 79. Milled top of 6-5/8" liner down 2' (top at 6905'). Circulated clean. Pulled out of well. Made up 5-3/4" x 2-1/4" taper mill. Ran in and reamed thru top of 6-5/8" liner. Pulled up to top of liner and secured well.
MWO 99183 $282,000 Daily $ 4,780
Cumulative $449,765

9-17-90 Patterson
Day 80. Pulled and laid down 5-3/4" OD taper mill. Loaded out all fishing tools. Ran 7-5/8" bit and 8-5/8" 36#/ft casing scraper to liner top (6902' D.P.). Started out of well with scraper. Secured well.
MWO 99183 $282,000 Daily $ 5,437
Cumulative $455,202

9-19-90 Patterson
Day 81. Pulled out of well with bit and 8-5/8" scraper. Ran Vertilog 8-5/8" casing inspection log from surface to 6898' (tagged 6-5/8" liner top at 6902'). Found areas of corrosion in 8-5/8" casing at 6832', 2350', and 966' (correlated to NLL, 11-18-72). Ran 5-5/8" bit and 6-5/8" 28#/ft. casing scraper to 7184' and then started out of hole. Secured well.
MWO 99183 $282,000 Daily $ 19,998
Cumulative $475,200

9-19-90 Patterson
Day 82. Pulled out of well with bit and 6-5/8" scraper. Ran in hole with 5" OD x 10' long Cavins surge tool assembly on 10 joints 2-7/8" tubing, crossed over to 3-1/2" drillpipe. Surged 6-5/8" liner and worked tool from 7185'-7188'. Pulled tool and recovered 3 gallons of iron cuttings and sand, plus a 26" piece of 6-5/8" casing. Ran kill string. Secured well.
MWO 99183$282,000 Daily $ 4,358
Cumulative $479,558

9-20-90 Patterson
Day 83. Pulled kill string. Ran 5" OD x 10' long surge tool assembly on 10 joints 2-7/8" tubing, crossed over to drillpipe. Worked surge tool to 7188' and surged 6-5/8" liner. Pulled surge tool - recovered small amount of wire wrap pieces and small packer pieces. Started in well with Model C retrievable bridge plug and Model C-1 fullbore retrievable packer.
MWO 99183 $282,000 Daily $ 5,920
Cumulative $485,478

9-08-90 Woods
Day 73. Mixed 70 bbls. of fluid. Continued to wash over 2-3/8" liner from 7034'-7101'. Backscuttled well clean. Started out of well to check mill shoe.
MWO 99183 $282,000 Daily $ 7,045
Cumulative $414,857

9-10-90 Woods
Day 74. Finished pulling out. Had 156' of 2-3/8" liner stuck in wash pipe. Laid down fish. Found shoe full of junk. Changed shoe and ran in wash over liner from 7086' - 7127'. Backscuttled clean work and jarred wash pipe free. Backscuttled clean. Secured well.
MWO 99183 $282,000 Daily $ 6,786
Cumulative $421,643

9-11-90 Woods
Day 75. Continued to mill and wash over 2-3/8" liner from 7127' to 7170'. Unable to make any hole. Attempted to backscuttle but tools plugged. Pulled out of well slow with wet pipe.
MWO 99183 $282,000 Daily $ 6,672
Cumulative $428,315

9-12-90 Woods
Day 76. Finished pulling out wet. Recovered 78' of 2-3/8" liner (screen) from wash pipe. Made up new shoe. Ran in mill and washed over 2-3/8" liner from 7164' to 7182' (mill on bottom). Backscuttled clean and pulled out of well. Secured well.
MWO 99183$282,000 Daily $ 6,266
Cumulative $434,581

9-13-90 Woods
Day 77. Pulled out of well. No recovery. Laid down wash pipe and made up overshot for 2-3/8" liner. Ran in well to top of liner.
MWO 99183 $282,000 Daily $ 5,761
Cumulative $440,342

9-14-90 Woods
Day 78. Ran in and attempted to work overshot over top of 2-3/8" liner to 7187'. Pulled out of well. No fish in overshot. Made up 7-5/8" string mill. Ran in well to top of liner. BOPE drill with crew - 49 seconds. Secured well.
MWO 99183 $282,000 Daily $ 4,643
Cumulative $444,985

8-31-90 Patterson
Day 67. Pulled out of well with packer retrieving tool. Recovered 6-5/8" Retrieva-D packer (bottom 2.65') ported extension, lower seal bore, 4" extension sub, X-overs (2), 2-3/8" shear-out safety joint, 2-3/8" collar, and severed 2-3/8" liner (0.17' long). Ran 5" mill shoe, 10 joints washpipe (5" OD x 4-1/4" ID x 289.47' long), drive sub, jars, and drill pipe to 6885'. Mixed new fluid and changed well over to 76#/cu.ft. workover fluid. Secured well.
MWO 99183 $282,000 Daily $ 5,043
Cumulative $379,863

9-01-90 Patterson
Day 68. Pumped 70 barrels of calcium chloride fluid before getting 76 lb/cu.ft. returns. Circulated and conditioned well fluid to 76 lbs./cu.ft. and 40 sec./qt. viscosity. Secured well.
MWO 99183 $282,000 Daily $ 6,013
Cumulative $385,876

9-04-90 Woods
Day 69. Rig is down to repair mud pump with new liners.
MWO 99183 $282,000 Daily $ 0
Cumulative $385,876

9-05-90 Woods
Day 70. Milled and washed over 2-3/8" liner from 6829' to 6939'. Pulled to kill string. Slipped and cut drilling line. Pulled out of well. Had 17' of 2-3/8" liner inside of wash pipe. Laid down fish. Made up new mill shoe on 5" wash pipe. Ran kill string. Secured well.
MWO 99183 $282,000 Daily $ 8,274
Cumulative $394,150

9-06-90 Woods
Day 71. Milled and washed over 2-3/8" liner from 6939' to 7012'. Milled lugs at 6979' and 6994'. Unable to make hole. Checked backscuttle tool (o.k.). Backscuttled clean. Started out of well to check mill shoe.
MWO 99183 $282,000 Daily $ 7,247
Cumulative $401,397

9-07-90 Woods
Day 72. Finished pulling out of well. Changed out mill shoe and ran in well. Milled and cleaned out junk and sand from 7012'-7034'. Backscuttled well clean. Pulled wash pipe to top of 6-5/8" liner. Well took 30 bbls of fluid.
MWO 99183 $282,000 Daily $ 6,415
Cumulative $407,812

8-24-90 Killebrew
Day 61. Milled element and 6-5/8" from 6902'-6903'. Circulated and cleaned well with three sacks. Sawdust backscuttled. Pulled 40 stands. Secured well.
MWO 99183 $282,000 Daily $ 4,713
Cumulative $334,676

8-25-90 Killebrew
Day 62. Finished pulling mill shoe. Recovered one quart of metal and one piece of rubber. Made up Homco Bowen 7-3/8" overshot with a 5-1/2" grapple and bottom hole assembly. Ran in well to 6896'. Jarred on fish to 135,000#. Pulled to 2050'. Secured well.
MWO 99183 $282,000 Daily $ 6,408
Cumulative $341,084

8-27-90 Killebrew
Day 63. Pulled out of well. Changed from 5-1/2" to 5-3/8" grapple. Ran in to 6896'. Jarred on fish to 160,000 lbs. Pulled out of well. Laid down overshot. Made up 7" x 6-1/4" x 12' washover pipe and surge tools. Ran in well to 2450'. Secured well.
MWO 99183 $282,000 Daily $ 4,503
Cumulative $345,587

8-28-90 Killebrew
Day 64. Ran in well with surge tool. Unable to get the 7" x 6-1/4" wash pipe over the packer. Surged for junk at 6895' - 6900'. Pulled surge tool . Recovered two pieces of metal. Made up Homco Bowen overshot with 5-1/2" grapple. Ran in well to 6903'. Unable to attach grapple to fish. Secured well.
MWO 99183 $282,000 Daily $ 8,024
Cumulative $353,611

8-29-90 Killebrew
Day 65. Pulled out of well with 5-1/4" grapple . Made up 4-1/2" grapple and ran in well to 6897'. Jarred on fish to 202,000 lb. - 110,000 lb. over string weight. Pulled out of well to 2100'. Secured well.
MWO 99183 $282,000 Daily $ 12,188
Cumulative $365,799

8-30-90 Patterson
Day 66. Pulled out of well with overshot fishing assembly. Recovered 4-11/16" close-catch overshot bowl, Baker latch-in locator sub (damaged from milling), two seal units, production tube, and two small diameter seal units (lower seal bore). Ran Baker Retrieva-D packer retrieving tool to 6900' and attached to packer. Jarred to 152,000 lbs (56,000 lbs over string weight) for one hour. Lost resistance--pulled to kill string.
MWO 99183 $282,000 Daily $ 9,021
Cumulative $374,820

8-16-90 Woods
Day 55. Pulled out of well. 4-5/8" grapple gone from overshot. Made up 7-3/8" mill shoe built up to 7.5" OD x 5.6" ID with tungsten carbide insert buttons. Ran in to 6897'. Backscuttled well clean and worked over fish to 6898'. Hydraulic hoses blew out on rotary table. Secured well and shut down to repair.
MWO 99183 $282,000 Daily $ 7,175
Cumulative $305,091

8-17-90 Woods
Day 55. Continued to mill on 6-5/8" casing at 6897'. Attempted to drill with no pump for 30 minutes. Would not mill. Hydraulics on rotary table bad. Laid down backscuttle tools. Checked out rotary hydraulics. Milled 9-1/2 hours.
MWO 99183 $282,000 Daily $ 4,247
Cumulative $309,338

8-18-90 Woods
Day 56. Rig is down to repair rotary table hydraulics.
MWO 99183 $282,000 Daily $ 1,650
Cumulative $310,988

8-20-90 Killebrew
Day 57. Repaired brakes and mud pump. Started milling at 11:00 a.m. Cleaned out to 6899'. Pulled mill shoe #4. Made up mill #5 and ran in to 2059'. Secured well.
MWO 99183 $282,000 Daily $ 4,175
Cumulative $315,163

8-21-90 Killebrew
Day 58. Finished running in well with 7-1/2" x 5-1/2 mill shoe. Continued to mill 6-5/8" 28# liner from 6899' to 6902'. Circulated bottoms up. Secured well.
MWO 99183 $282,000 Daily $ 6,296
Cumulative $321,458

8-22-90 Killebrew
Day 59. Pulled mill #5. Made up 7-1/2" x 5-1/2" mill shoe #6. Ran in well to 2600'. Closed in well. Changed drill line.
MWO 99183 $282,000 Daily $ 6,337
Cumulative $327,795

8-23-90 Killebrew
Day 60. Rig down at 7:00 a.m. to replace brakes until 3:00 p.m. Ran in to 6270'.
MWO 99183 $282,000 Daily $ 2,168
Cumulative $329,963

8-10-90 Killebrew
Day 50. Pulled kill string. Made up cavins surge tool. Ran in well and surged from 6892' to 6900'. Pulled out of well to kill string. Secured well.
MWO 99183 $282,000 Daily $ 3,945
Cumulative $272,897

8-11-90 Killebrew
Day 51. Pulled out of well with surge tool. Recovered one gallon of metal plus two slivered pieces of 6-5/8" liner (each approx. 11' long). Made up Homco 4-5/8" grapple in 7-3/8" Bowen overshot, 6" bumper-sub, 6" jars, 4-6" drill collars and accelerator. Ran in well to 6896' and attached to fish. Jarred on fish. Pulled out of well. Recovered 6" piece of 6-5/8". Ran kill string. Secured well.
MWO 99183 $282,000 Daily $ 8,003
Cumulative $280,900

8-13-90 Woods
Day 52. Pulled kill string. Made up 7-1/16" impression block on two joints 2-7/8" tubing. I.B. showed 1-3/16" x 3/16" mark in center of block. Ran to 6900' on sand line. Had to cut and splice sand line on way out (3-1/2 hours). Finished pulling out. Changed out Hydril bag. Made up 5-3/4" x 2-1/2" taper mill. Ran kill string.
MWO 99183 $282,000 Daily $ 4,258
Cumulative $285,971

8-14-90 Woods
Day 53. Finished running in. Stopped at 6896'. Milled to 6897'. Pulled out. Mill showed to wear on 5-3/4" O.D. Had 2 pieces of tubing 6" long 2" wide in mill. Laid down mill. Made up 5-5/8" x 4-3/4 gr. overshot. Ran in to 20 stands. Change of orders. Pulled out to kill string.
MWO 99183 $282,000 Daily $ 6,117
Cumulative $292,088

8-15-90 Woods
Day 54. Finished running in well. Latch on fish at 6897'. Jarred on fish to 180,000#. Overshot started slipping out. Pulled out of well to kill string. BOPE drill with crew - 46 seconds.
MWO 99183 $282,000 Daily $ 5,820
Cumulative $297,916

8-01-90 Killebrew
Day 42. Finished running in well. Reamed from 6887' - 6892'. Continued milling 6-5/8" 28# liner from 6892' to 6897'.
MWO 99183 $282,000 Daily $ 4,894
Cumulative $229,756

8-02-90 Killebrew
Day 43. Milled and cleaned out rubber from 6897' - 6898'. Secured well.
MWO 99183 $282,000 Daily $ 6,034
Cumulative $235,790

8-03-90 Killebrew
Day 44. Pulled out of well with Homco 7-1/2" x 5-1/2" mill shoe. Made up Cavins surge tool. Ran in well to 3100'.
MWO 99183 $282,000 Daily $ 3,317
Cumulative $239,107

8-04-90 Killebrew
Day 45. Finished running in well with Cavins surge tool. Surged at 6893'. Pulled out of well. Recovered one gallon of metal and rubber. Made up 2-3/4" basket grapple on bumper sub, jars, four 6" drill collars. Ran in well to 5883'.
MWO 99183 $282,000 Daily $ 7,014
Cumualtive $246,121

8-06-90 Killebrew
Day 46. Ran in well and attached grapple to 2-7/8" tubing at 6887'. Jarred on fish to 170,000 lb. Tried to work packer down hole. Pulled out of hole wet. Recovered metal, rubber, a piece of 2-7/8" tubing 12" long. Ran kill string to 2100'. Secured well.
MWO 99183 $282,000 Daily $ 5,742
Cumulative $251,863

8-07-90 Killebrew
Day 47. Pulled kill string. Made up Homco 7-1/2" x 5-1/2" mill shoe. Ran in well. Milled over packer from 6894' to 6898'. Sheared bolts on rotary table drive shaft at 3:45 p.m. Closed in well until a.m.
MWO 99183 $282,000 Daily $ 7,546
Cumulative $259,409

8-08-90 Killebrew
Day 48. Continued milling on 6-5/8" liner at 6898'. Rubber and metal returns over shale shaker. Milled to 6898'.
MWO 99183 $282,000 Daily $ 4,911
Cumulative $264,320

8-09-90 Killebrew
Day 49. Milled from 6899' to 6900'. Backscuttled and circulated bottoms up. Pulled to kill string.
MWO 99183 $282,000 Daily $ 4,632
Cumulative $268,992

7-24-90 Killebrew
Day 35. Pulled kill string. Made up shoe and washover pipe running in well (15 stands per hour) to avoid fluid from flowing over top of 3-1/2" drill pipe.
MWO 99183 $282,000 Daily $ 4,258
Cumulative $194,085

7-25-90 Killebrew
Day 36. Finished running in well to 6883' with sawtooth washover shoe. Milled between 6-5/8" x 8-5/8" pipe for 70 minutes - made 3". Circulated bottoms up. Recovered gravel and small metal stringers.
MWO 99183 $282,000 Daily $ 4,258
Cumulative $198,343

7-26-90 Killebrew
Day 37. Milled with sawtooth between 8-5/8" x 6-5/8" pipe for 90 minutes (no progress). Pulled out of well. Sawtooth showed no wear. Ran kill string. Secured well.
MWO 99183 $282,000 Daily $ 6,020
Cumulative $204,363

7-27-90 Killebrew
Day 38. Made up 5" surge tool. Ran in well and surged from 6883' to 6890'. Pulled out of well with surge tool, recovered metal cuttings. Made up Homco 7-1/2" x 5-1/2" mill shoe on 38' wash pipe. Ran in well with kill string to 2090'. Secured well.
MWO 99183 $282,000 Daily $ 5,797
Cumulative $210,160

7-28-90 Killebrew
Day 39. Ran in well with Homco 7-1/2" x 5-1/2" mill shoe. Milled from 6883' to 6889'. Broke high pressure hydraulic hose on rotary table at 3:30 p.m. Circulated well clean. Cleaned ditch magnet. Secured well.
MWO 99183 $282,000 Daily $ 3,945
Cumulative $214,105

7-30-90 Killebrew
Day 40. Cleaned out 2' fill. Milled 6". Rig down for repair. Working on hydraulic system for rotary table.
MWO 99183 $282,000 Daily $ 6,499
Cumulative $220,604

7-31-90 Killebrew
Day 41. Milled on 6-5/8" liner from 6889' to 6892'. Pulled millshoe #1. Made total of 9'. Heeled off 3/8". Made up mill shoe #2. Ran in well to 3596'. Secured well.
MWO 99183 $282,000 Daily $ 4,258
Cumulative $224,862

7-16-90 Woods
Day 28. Milled on 6-5/8" 28# liner and hanger from 6863' to 6868'. Backscuttled clean. Pulled up and secured well.
MWO 99183 $282,000 Daily $ 5,296
Cumulative $159,151

7-17-90 Woods
Day 29. Milled on 6-5/8" 28# liner from 6868' to 6870'. Total footage milled - 11'. Circulated clean. Pulled out mill #1 (50% used). Made up mill #2. Ran kill string and secured well.
MWO 99183 $282,000 Daily $ 4,736
Cumualtive $163,887

7-18-90 Woods
Day 30. Finished running in mill down to liner at 6870' two hours (would not mill). Pulled out with mill #2. Cut bottom wing off mill. Made up tools. Ran kill string in well. Secured well.
MWO 99183 $282,000 Daily $ 4,258
Cumulative $168,145

7-19-90 Woods
Day 31. Milled on 6-5/8" liner from 6870' to 6882'. Circulated clean. Secured well. BOPE drill - 50 seconds.
MWO 99183 $282,000 Daily $ 7,631
Cumulative $175,776

7-20-90 Woods
Day 32. Pulled out of well. Made up washover mill shoe 7-9/16" OD x 5-9/16" ID on 6" drill collars. Ran in to 6800'. Secured well. Repaired tongs (1/2 hour).
MWO 99183 $282,000 Daily $ 3,735
Cumulative $179,511

7-21-90 Woods
Day 33. Milled on 6-5/8" liner from 6882' to 6883'. Circulated well clean and pulled out of well. Laid down wash pipe. Ran kill string. Secured well.
MWO 99183 $282,000 Daily $ 9,766
Cumulative $189,277

7-23-90 Killebrew
Day 34. Rig and crew idle - short one man. Homco adding tungsten carbide and boron to mill shoe.
MWO 99183 $282,000 Daily $ 550
Cumulative $189,827

7-07-90 Killebrew
Day 21. Pulled kill string. Made up midway overshot with 2-7/8" grapple. Ran in well and attached grapple to 2-7/8" fish at 6889'. Jarred and worked fish to 140,000 lbs. (50,000 lbs. over hook weight). Pulled out of well to kill string, hydraulic tongs down for repair.
MWO 99183 $282,000 Daily $ 4,153
Cumulative $115,512

7-09-90 Killebrew
Day 22. Rig down for repair. Working on hydraulic pipe tongs.
MWO 99183 $282,000 Daily $ 447
Cumulative $116,062

7-10-90 Killebrew
Day 23. Rig started running at 8:30 a.m. Pulled out of well. No recovery. Made up 5-1/16" x 4" mill shoe on bottom hole assembly and ran in well to 6823'.
MWO 99183 $282,000 Daily $ 8,464
Cumulative $124,526

7-11-90 Killebrew
Day 24. Ran in and milled on junk at 6892'. With reverse circulating tool. Pulling out of well with 50 stand. Rig down from 12:30 - 3:00 p.m. Finished pulling out of well. Laid down mill. Made up Midway grapple on bottom hole assembly. Ran in to 2057'. Secured well.
MWO 99183 $282,000 Daily $ 3,735
Cumulative $128,261

7-12-90 Killebrew
Day 25. Finished running in well to latch at 6892'. Attached grapple to latch and jarred to 180,000 lbs. (90,000 lbs. over hook weight). Pulled out of well. Left overshot bowl and grapple. Recovered a piece of metal out of extension (10" long - 2" wide) with threads. Ran kill string.
MWO 99183 $282,000 Daily $ 6,761
Cumulative $135,022

7-13-90 Killebrew
Day 26. Pulled kill string. Modify pilot mill. Ran in well to 6859'. Circulated and conditioned drilling fluid.
MWO 99183 $282,000 Daily $ 6,721
Cumulative $141,743

7-14-90 Killebrew
Day 27. Milled on 6-5/8" 28# liner and 6-5/8" x 8-5/8" liner hanger from 6859' to 6863'. Secured well.
MWO 99183 $282,000 Daily $ 12,112
Cumulative $153,855

6-29-90 Woods
Day 15. Attached grapple to fish. Jarred and worked pipe attempting to release latch and seals. Pulled out of well. No recovery. Ran kill string and secured well.
MWO 99183 $282,000 Daily $ 5,048
Cumulative $ 92,139

6-30-90 Woods
Day 16. Rig shut down. Insufficient rig personnel (no derrickman).
MWO 99183 $282,000 Daily $ 550
Cumulative $ 92,689

7-02-90 Killebrew
Day 17. Pulled kill string. Made up 5" washpipe with sawtooth on bottom and 4-3/4" overshot. Ran in well to 6890' and backscuttled for 45 minutes. Attached to fish and worked 7 rounds of torque into pipe. Latch did not release. Released overshot from fish. Pulling out of well.
MWO 99183 $282,000 Daily $ 6,009
Cumulative $ 98,698

7-03-90 Killebrew
Day 18. Pulled out of well. Made up outside cutting tool. Running in well. Rig shut down for repairs on right angle drive.
MWO 99183 $282,000 Daily $ 3,279
Cumulative $101,977

7-04-90 Killebrew
Day 19. Rig and crew idle. Holiday.
MWO 99183 $282,000 Daily $ 3,279
Cumulative $101,977

7-05-90 Killebrew
Day 19. Ran in and out of 2-7/8" tubing at 6889' just above packer. Pulled out of well. Recovered 27.12' of 2-7/8" tubing. Made up Midway grapple on fishing assembly and started running in well to 1970'. Secured well.
MWO 99183 $282,000 Daily $ 5,851
Cumulative $107,828

7-06-90 Killebrew
Day 20. Finish running in well to fish at 6892'. Backscuttled - 45 minutes. Attempted to attach grapple to latch with no success. Pulled out of well to kill string 2050'. Secured well.
MWO 99183 $282,000 Daily $ 3,526
Cumulative $111,359

6-22-90 Woods
Day 9. Repaired Foster Tongs (two hours). Pulled kill string. Made up fishing tools. Waited on sub. Blocks fell 3' to floor when fast line came out of drum. Shut rig down to wait on new drilling line. Strung new drilling line. Secured well. (Downtime on rig 9 hours).
MWO 99183 $282,000 Daily $ 2,377
Cumulative $ 57,906

6-23-90 Woods
Day 10. Made up fishing tools. Ran in and attempted to screw onto fish. Pulled loose from fish at 30,000 lbs. over. Ran chemical cutter. Tool stopped at 6861'. Pulled chemical cutter and CCL. Circulated and attempted to screw onto fish - would come off fish at 30,000 lbs. over. Backscuttled clean. Secured well.
MWO 99183 $282,000 Daily $ 5,672
Cumulative $ 63,578

6-25-90 Woods
Day 11. Pulled out of well. Picked up one joint of 5" washover pipe with mill shoe. Ran in and circulated over fish from 6863' - 6892'. Backscuttled clean. Pulled to top of fish. Secured well.
MWO 99183 $282,000 Daily $ 4,258
Cumulative $ 67,836

6-26-90 Woods
Day 12. Ran into well at 6892'. Backscuttled for thirty minutes. Pulled out of well with wash pipe. Laid down washover pipe. Made up Bowen overshot and ran in well to 4760'. Closed in well to repair blocks at 4:00 p.m.
MWO 99183 $282,000 Daily $ 3,840
Cumulative $ 71,676

6-27-90 Woods
Day 13. Finished running in well and attached grappel to fish at 6861'. Jarred on latch and seals, worked pipe free. Pulling out of well to 1800'. Secured well.
MWO 99183 $282,000 Daily $ 3,004
Cumulative $ 74,680

6-28-90 Woods
Day 14. Pulled out of well. Made up Midway's Baasch Ross 3-1/16" grapple. Ran in well to 6690'. Secured well.
MWO 99183 $282,000 Daily $ 12,411
Cumulative $ 87,091

6/29/90. [illegible]

6-15-90 Killebrew
Day 3. Attempted to release seals and latch from packer with no success. Using Dialog ran free point and back off shot. Combination free point showed movement of pipe to packer. Fired string shot in packer at 6893', but unable to unlatch from packer. Pulled Dialog tools. Secured well.
MWO 99183 $282,000 Daily $ 3,758
Cumulative $ 32,559

6-16-90 Killebrew
Day 4. Using Dialog backed off 2-7/8" tubing at 6861'. Pulled and re-dressed doughnut. Using hydrotest, tested pipe rams, blind rams and manifold to 4000 psi. Tested Hydril bag to 2700 psi. Layed down doughnut and secured well.
MWO 99183 $282,000 Daily $ 8,001
Cumulative $ 40,560

6-18-90 Killebrew
Day 5. Pulled 2-7/8" 6.5# J-55 8rd EUE tubing and accessories, leaving one joint of tubing latched into the packer. Changed pipe rams from 2-7/8" to 3-1/2". Ran 2-7/8" tubing kill string in well. Picked up and stood back kelly and 6" drill collars. Rigged up to pick up 3-1/2" drill pipe. Secured well.
MWO 99183 $282,000 Daily $ 3,658
Cumulative $ 44,218

6-19-90 Woods
Day 6. Pulled kill string. Made up 5" mill shoe, one joint of 5" wash pipe, bumper sub, and jars. Picked up and ran 3-1/2" IF drill pipe to 6800'. Secured well.
MWO 99183 $282,000 Daily $ 4,258
Cumulative $ 48,476

6-20-90 Woods
Day 7. Located 6-5/8" liner top at 6859'. Shut down for 7 hours to repair leak in stand pipe and to replace swivel packing. Backscuttled and cleaned out sand from 6861' (top of 2-7/8" tubing) to 6892' (top of packer). Secured well.
MWO 99183 $282,000 Daily $ 2,795
Cumulative $ 51,271

6-21-90 Woods
Day 8. Wash over fish from 6861' - 6892'. Backscuttled sand out of well. Pulled out of well. Laid down wash pipe, had no x-over sub from 3-1/2" FH box to 2-7/8" 8rd pin. Ran kill string. Secured well. Had BOPE drill - 56 seconds.
MWO 99183 $282,000 Daily $ 4,258
Cumulative $ 55,529

6-06-90 Killebrew
Day 0. Load and moved rig from WEZU 24B (Honor Rancho) to Fernando Fee 35C. Set in rig.
MWO 99183 $282,000 Daily $ 1,850
Cumulative $ 1,850

6-07-90 Killebrew
Day 0. Welding repairs made to derrick. Rig crew cleaning up WEZU 24B location.
MWO 99183 $282,000 Daily $ 0
Cumulative $ 1,850

6-08-90 Killebrew
Day 0. Begin rigging up - string drilling line.
MWO 99183 $282,000 Daily $ 12,723
Cumulative $ 14,573

6-09-90 Killebrew
Day 0. Continue rigging up over well.
MWO 99183 $282,000 Daily $ 1,475
Cumulative $ 16,048

6-11-90 Killebrew
Day 0. Rig and crew idle due to shortage of rig personnel.
MWO 99183 $282,000 Daily $ 550
Cumulative $ 16,598

6-12-90 Killebrew
Day 0. Continued rigging up.
MWO 99183 $282,000 Daily $ 2,331
$ 18,929

6-13-90 Killebrew
Day 1. Using instrument service checked fluid level and pressure. (Annulus 1346', 450 psi - tubing 1426' 500 psi). Set back pressure valve. Removed xmas tree and installed BOPE. Secured well.
MWO 99183 $282,000 Daily $ 5,706
Cumulative $ 24,635

6-14-90 Killebrew
Day 2. Using Hydrotest, tested BOPE. Donut leaking fluid. No test. Tubing and annulus pressure 74 psig. Tubing Fluid level 267', annulus fluid level 441'. Pressure release tubing hanger from tubing head. Work tubing trying to release seals and latch from Baker Retrieva "DA" packer.
MWO 99183 $282,000 Daily $ 4,165
Cumulative $ 28,801

Ex. I – 45

9-21-90 Patterson

Day 84 Finished running in well with packer and bridge plug. Set bridge plug at 6895' (top) and tested 8-5/8" casing to 700. Set packer at 5601' and tested to 1500 psi (5601'-6895'). Recovered bridge plug and set at 5633'. Tested 8-5/8" casing to 900 psi (o'-5633'). Set bridge plug at 4407' and tested 8-5/8" casing to 1500 psi (0'-4107'). All tests good-no leaks. Started out of well with packer and bridge plug.

MWO 99183 $282,000 Daily $ 7,650
Cumulative $493,128

9-22-90 Patterson

Day 85. Pulled out of well and laid down Model "C" packer and retrievable bridge plug. Left piece of bow spring (7-1/4" x 1-5/8" x 3/16") from plug in well. Ran Halliburton 8-5/8" 36# x 6-5/8" 28# lead seal driveover adapter and set on top of 6-5/8" liner at 6902' (top of lead seal at 6900'). Started out of well with setting tool.

MWO 99183 $282,000 Daily $ 8,152
Cumulative $501,280

9-24-90 Patterson

Day 86. Pulled out with lead seal adapter setting tool. Ran 5-5/8" bit on 2-7/8" tubing, crossed over to 3-1/2" drillpipe to 7190' - unable to work deeper. Circulated well clean. Cleaned circulating pit and all Baker tanks. Pulled bit up above liner top. Secured well.

MWO 99183 $282,000 Daily $ 6,344
Cumulative $507,624

9-25-90 Patterson

Day 87. Ran in hole with 5-5/8" bit to 7190'. Filtered 270 bbls. CaCl workover fluid on surface. Circulated well and filtered 300 bbls. of wellbore workover fluid. Secured well.

MWO 99183 $282,000 Daily $ 8,493
Cumulative $516,117

9-26-90 Patterson

Day 88. Completed filtering of all CaCl workover fluids on the surface and in the well. Pulled out of well with 5-5/8" bit and 6-5/8" casing scraper. Made up Vann tubing conveyed perforating assembly, maximum differential bar vent, 8-5/8" RTTS packer, and annulus valve on 3-1/2" drillpipe. Ran in hole to 6800'. Secured well.

MWO 99183 $282,000 Daily $ 8,616
Cumulative $524,733

9-27-90 Patterson

Day 89. Completed running in hole. Tagged bottom of hole with perforating assembly and picked up 10' to set packer and test lines. Waited for Gas Co. personnel to tie choke manifold into kill line. Ran GR correlation log from 6800' - 7000'. Reset packer 10' lower. Pressured well to 2150' psi surface pressure for 150 psi underbalance (est. fluid level: 5800'). Dropped perforating bar - pressure built to 2300 psi. Flowed well for 11 minutes. Killed by bullheading 78 bbls. Secured well.

MWO 99183 $282,000 Daily $ 11,734
Cumulative $536,467

9-28-90 Patterson

Day 90. Bled off drillpipe and annulus. Ran pulling tool and hydraulic jars on 0.092" slick line and recovered Vann drop bar. Dropped bar for second perforation firing attempt - no indication of firing. Latched onto drop bar with slickline pulling tool and spudded tools twice at 7027'. Recovered drop bar. Pulled perforating assembly - guns failed to fire due to fine metal and rock debris above firing head. Ran drillpipe kill string.

MWO 99183 $282,000 Daily $ 8,528
Cumulative $544,995

9-29=90 Patterson

Day 91. Pulled kill string. Re-ran 4" Vann perforating assembly, maximum differential bar vent, 8-5/8" RTTS packer, and annulus valve on 3-1/2" drillpipe. Positioned guns (to perforate 7070'-7110' and 7149'-7179', 4 HPF) and set packer at 6839'. With fluid level in drillpipe at 1525' (for 200 psi underbalance), dropped firing bar. Noticed 600' rise in fluid level (stabilized). Pumped 17 bbls and pulled 6 stands. Secured well.

MWO 99183 $282,000 Daily $ 5,109
Cumulative $550,104

10-1-90 Patterson

Day 92. Laid down packer and guns, and loaded out. Made up bit and casing scaper for 6-5/8" casing. Ran in well and located fill at 7188', cleaning out to 7190' (2' of fill). Backscuttled gas out of well. Pulled to top of liner.

MWO 99183 $282,000 Daily $ 20,623
Cumulative $570,727

10-2-90 Patterson
Day 93. Pulled out of well. Rigged up to pick up 2-3/8" wire wrapped liner. While picking up liner over torque, pipe had bad box. Laid down liner. Ran kill string.
MWO 99183 $282,000 Daily $ 2,317
Cumulative $574,044

10-3-90 Woods
Day 94. Pulled kill string. Ran 2-3/8" wire wrap liner (249.88' total). Picked up 1.315" OD tail pipe. Ran in well to 7179' (top at 6930'). Mixed and pumped slurry with 45 cu.ft. of 40-60 sand. Established 21 cu.ft. in place when pressure went from 626 psi to 1200 psi. Backscuttled sand out with pressure at 2000 psi.
MWO 99183 $282,000 Daily $ 6,454
Cumulative $578,302

10-4-90 Woods
Day 95. Circulated 3 barrels per minute at 700 psi. Pumped 15 cu.ft. 40-60 sand. Backscuttled well clean-no sand. Waited 2 hours. Break circulation at 3 barrels per minute. Pumped 10 cu.ft. 40-60 sand. Pressured to 1200 psi. Backscuttled well clean-no sand. Waited 1-1/2 hours. Break circulation at 3 barrels per minute and 800 psi. Secured well.
MWO 99183 $282,000 Daily $ 6,454
Cumulative $584,756

10-5-90 Woods
Day 96. Mixed and pumped 11 cu.ft. of 40-60 sand down at 1.5 bbls. per minute. Unsuccessfully attempted to backscuttle. Released from liner. Worked tool to top of 6-5/8" liner. Freed pipe backscuttled clean-no sand. Pulled out of well and laid down tubing with tools. Ran kill string.
MWO 99183 $282,000 Daily $ 5,423
Cumulative $590,179

10-6-90 Woods
Day 97. Rigged up Atlas Wireline. Ran Photon Log. Stopped liner top. Pulled out of well and removed centralizer. Added weight. Ran in, stopped at liner top. Riiged down Atlas and ran in with 1" tubing. Located fill at 7169'. Backscuttled fill out of well. Pulled out of liner and secured well.
MWO 99183 $282,000 Daily $ 7,817
Cumulative $597,996

10-8-90 Woods
Day 98. Rigged up Atlas Wireline. Ran Photon Log. Stopped at 6963'. Pulled out of well and added weight bars. Ran in well to 7080'. Could not go down. Logged up to 6700'. Pulled out of well. Loaded out Atlas Wireline and ran kill string. Secured well.
MWO 99183 $282,000 Daily $ 7,520
Cumulative $605,516

10-9-90 Woods
Day 99. Made up Halliburton lead seal drive over adaptor and ran in well to 2-3/8" liner top. Set lead seal adapter (top at 6927'). Released from lead seal. Pulled out of well. Made up and set Baker bridge plug at 5925'. Tested to 1000 psi. Pulling out of well laying down drill pipe.
MWO 99183 $282,000 Daily $ 28,003
Cumulative $633,5196

10-10-90 Woods
Day 100. Laid down 3-1/2" IF drill pipe (217 joints), 6" drill collars and tools. Changed out Tongs. Ran kill string. Secured well.
MWO 99183 $282,000 Daily $ 4,571
Cumulative $ 638,090

10-11-90 Woods
Day 101. Loaded out tools. Lowered cellar floor.
MWO 99183 $282,000 Daily $ 6,510
Cumulative $644,660

10-12-90 Woods
Day 102. Digging out cellar floor with S & E construction crew to lower wellhead.
MWO 99183 $282,000 Daily $132,863
Cumulative $777,523

10-13-90 Woods
Day 103. Pulled kill string. Rigged up to unland 8-5/8" casing. Attempted to remove tubing head and 8-5/8" seal flange. Pulled 68,000 lb. could not break seal flange loose. Made up tubing head and BOPE. Ran kill string. Secured well.
MWO 99183 $282,000 Daily $ 3,779
Cumulative $781,302

10-15-90 Woods
Day 104. Cut casing head off and lowered 33". Welded new 13-5/8" casing head on. Cooled for 2 hours. X-ray weld (o.k.). Relanded 8-5/8" casing with 100,000# weight in slips. Installed 8-5/8" packing. Ran top bridge plug. Secured well.
MWO 99183 $282,000 Daily $ 6,763
Cumulative $788,065

10-17-90 Woods

Day 106. Nippled up BOPE, tested to 1000 psi (o.k.). Tested seal flange landing spool seal with 4000 psi (test o.k.). Laid down tools. Pulled top bridge plug from 60'. Ran in well to retrieve bridge plug set at 6000'. Found drilling line very bad. Changed out drilling line.

MWO 99183 $282,000 Daily $ 6,278
Cumulative $820,066

10-18-90 Woods

Day 107. Ran in latch plug. Released plug and pulled out. Laid down bridge plug. Rigged up wireline. Made up Otis 8-5/8" packer. Ran in and set at 6850'. Packer did not set and fell down well to top of liner. Rigged down wireline. Ran in with seal overshot. Attempted to latch onto packer, no indication at surface that packer was latched. Started out of well.

MWO 99183 $282,000 Daily $ 3,758
Cumulative $823,824

10-19-90 Woods

Day 108. Finished pulling out. Recovered Otis packer. Made up new packer. Rigged up Tiger wireline. Ran packer and set at 6850'. Loaded out Tiger wireline. Made up Otis test seals (overshot). Ran kill string. Secured well.

MWO 99183 $282,000 Daily $ 7,542
Cumulative $831,366

10-20-90 Woods

Day 109. Ran in and located packer at 6850'. Pulled 20,000# weight over set 10,000# down on packer. Tested packer with 1500 psi for 30 minutes (o.k.). Released from packer. Pulled out of well to kill string. Made breaks on kelly. Held BOPE drill with crew - 49 seconds. Secured well.

MWO 99183 $282,000 Daily $ 5,222
Cumulative $836,588

10-22-90 Woods

Day 110. Pulled kill string. Changed pipe rams to 6-5/8". Picked up 6-5/8" casing, Hydro-testing to 5000 psi, Torque-n-turn connections 4800' - 5500 ft-lbs. Ran to 2680'. Secured well.

MWO 99183 $282,000 Daily $ 6,358
Cumulative $842,973

10-23-90 Woods

Day 111. Continued running 6-5/8" N-80 AB FL-4S casing to 6847'. Located and latched packer. Pulled 20,000# over string weight. Set 10,000# on packer. Tested backside to 1,500 psi (o.k.). Released from packer. Rigged down Hydro-test and loaded out. Secured well.

MWO 99183 $282,000 Daily $ 16,562
Cumulative $859,555

10-24-90 Woods

Day 112. Rigged up and pumped 155 bbls. of 63# inhibited 2% KCL water to fill 6-5/8" - 8-5/8" casing annulus. Landed 6-5/8" on packer and pulled 20,000# over. Tested with 1500 psi (o.k.). Set top bridge plug. Removed BOPE. Installed slip and packing tubing head with 20,000# down in packer. Tested seal flange and tubing head to 5000 psi. BOPE to 1000 psi. Secured well.

MWO 99183 $282,000	Daily	$ 12,839
	Cumulative	$872,374

10-25-90 Woods

Day 113. Pulled bridge plug. Rigged up Hydro-test and made up production equipment. Ran in, Hydro-testing to 4000 psi. Located packer and pulled 20,000# over. Tested to 1500 psi (o.k.). Released from packer. Spaced out and landed tubing with 10,000# on packer. Installed back pressure valve. Removed BOPE and installed xmas tree. Secured well.

MWO 99183 $282,000	Daily	$ 30,018
	Cumulative	$902,407

10-26-90 Woods

Day 114. Tested xmas tree to 5000 psi. Rigged up Archer Reed wireline. Opened Otis (XD) sliding sleeve. Rigged down Archer Reed. Circulated 76# fluid out of well with 63# 2% inhibited KCl water. Released rig.

MWO 99183 $282,000	Daily	$ 4,297
	Cumulative	$906,704

10-26-90 Woods

Day 0. Rigged down and loaded out rig.

MWO 99183 $282,000	Daily	$ 600
	Cumulative	$907,304

Ex. I – 46

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION
DIVISION OF OIL, GAS, AND GEOTHERMAL RESOURCES

HISTORY OF OIL OR GAS WELL

Operator Southern California Gas Company Field Aliso Canyon County Los Angeles
Well Porter 32 Sec 27 3N 16W S.B.B.M.
A.P.I. No. 03700719 Name Tom McMahon (Person submitting report) Title SIMP Project Manager (President, Secretary, or Agent)
Date 3/8/2017 (Month, day, year)
Signature Thomas McMahon
Address PO Box 2300, SC9365, Chatsworth, CA, 91313-2300 Telephone Number 714-398-5020

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Start Date	Ops this Report (DOGGR)
9/23/2016	Mov in rig up equipment
9/24/2016	Bled well. 280 psi on Tubing 40 psi on Casing. Bleed well into Canister. Well would not Bleed down. Pressure rising on gauge. Rig up Mud pump. Waited on fluid. Pumped down tubing. No cumunication on back side. Pumped down back side. Presure up to 500 psi. Sleeve closed or plugged.
9/26/2016	Bled well off. Removed prduction tree. Installed 11" Class III BOP. Tested BOP. BOP Inspection witnessed by DOGGR.
9/27/2016	Attempt to pull seals out of Baker Model "D" Packer. No good. Wait on wire line. Rigged up Tiger wire line and chemical cut tubing at 7419'. (WLM). Pulled tubing hanger and pup joints.
9/28/2016	Pulled 2 3/8" tubing. Made up fishing tools. Picked up 2.7/8" work string.
9/29/2016	Ran in hole with wash pipe on 2 7/8" tubing. Stacked out a 5433'. Tripped out of hole. Ran kill string
9/30/2016	Tripped in hole. Attempted to wash over fish.
10/1/2016	Tripped out of hole. Checked shoe, good condition. Made up bent pup joint and tripped in hole.
10/3/2016	Tripped in hole. Washed over fish. Tripped out of hole to kill string
10/4/2016	Tripped in hole Latched on to fish. Jarred on fish. Fish came free or parted. Tripped out of to kill string.
10/5/2016	Tripped out of hole with kill string. Laid down fish. Recovered 14' of 2 3/8" tubing. Tripped in hole. Latched on to fish. Jarred on fish. Fish parted. Tripped out of hole.
10/6/2016	Tripped out of hole with fish. Recovered 2 feet of 2 3/8" tubing. Laid down 2 3/8" PH6 tubing. Ran kill string.
10/7/2016	Removed BOP. Unlanded 5 1/2" inner string. Installed BOP.
10/8/2016	Attempted to unjay 5 1/2" casing from packer, no good. Rigged up wire line and cut casing at 5414'. Laid down 3 joints.
10/10/2016	Laid down 100 joints of 5 1/2" Inner string casing.
10/11/2016	Laid down 5 1/2" inner casing. Made up fishing tools and tripped in hole. Latched on to fish. Jarred on fish. Tripped out of hole to 2900'.
10/12/2016	Tripped out of hole. Recovered fish. Tripped in hole with millshoe. Milled on packer.
10/13/2016	Tripped out of hole. Changed mill shoe. Tripped ing hole. Milled on packer.
10/14/2016	Tripped out of hole with wash over shoe. Made up overshot and tripped in hole. Latched on to fish. Tripped out of the hole with 20 stands.
10/15/2016	Tripped out of hole. Retrieved packer. Make up 7" scraper and trip in hole to 7438'.
10/17/2016	Tripped out of hole with scraper. Ran retievable bridge plug and set at 7435'. Tripped out of hole to kill string.
10/18/2016	Ran Schlumberger USIT and CBL Log
10/19/2016	Open up well high winds gust up to 52 MPH Wait for wind to die down. Shut down do to High winds close in well secure location
10/20/2016	Tripped in hole with retrieving tool. Circulated sout of hole. Latch onto bridge plug and released. Tripped out of hole to killstring.
10/21/2016	Tripped out of hole with bridge plug. Made up mill shoe and tripped in hole to 7438'. Millover packer from 7438' to 7440.5'.
10/22/2016	Milled on packer. Tripped ot of hole. Changed mill shoe. Tripped in hole with kilstring.

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION
DIVISION OF OIL, GAS, AND GEOTHERMAL RESOURCES

HISTORY OF OIL OR GAS WELL

Operator Southern California Gas Company Field Aliso Canyon County Los Angeles
Well Porter 32 Sec 27 3N 16W S.B.B.M.
A.P.I. No. 03700719 Name Tom McMahon (Person submitting report) Title SIMP Project Manager (President, Secretary, or Agent)
Date 3/8/2017 (Month, day, year)
Signature
Address PO Box 2300, SC9365, Chatsworth, CA, 91313-2300 Telephone Number 714-398-5020

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Start Date	Ops this Report (DOGGR)
10/24/2016	Tripped in hole. Milled over packer. Packer falling down hole. Tripped out of hole to kill string
10/25/2016	Tripped out of hole. Made up overshot and tripped in hole. Latched onto packer. Tripped out of hole with packer to kill string.
10/26/2016	Tripped out of hole. Laid down fish and fishing tools. Tripped in hole with retrievable bridge plug and set at 7440' COE. Tripped out hole. Made at 7" full bore test packer and tripped in hole to kill string.
10/27/2016	Tripped in hole with test packer to 7413'. Tested bridge plug to 500 psi. Good test. Tripped out of hole to 4600' with test packer. Tested below packer to 500 psi. Good test. Tested above packer no test. Tested cacing from 4600' to 1910'. Good test below packer. No test abve packer. Stared bleeding off at 1273'.. Pulled up to 669'. Getting communication through tubing tring to test above packer. Pulled up to 654'. Tested above packer to 500 psi. good test. tophole in casing is around 660'.
10/28/2016	Service Rig. Gauge Pressure on Tubing (0psi) and Casing (0psi). Pumped 8 bbls to fill casing. Gauge Tanks 355 bbls of fluid on location. POOH With 20 Joints of (2 7/8") P-110 tubing Change out Baker Hughes 7" Test packer. RIH With 48 Joints of (2 7/8") P-110 tubing Set packer at 1529' Test casing from 1502' down 7,443' Test good. Straddle casing. Casing test good from (1,323') to (7,443') and (653' to Surface. Holes Between 653' to 1,323'. POOH With (42) Joints of (2 7/8") P-110 tubing. Lay down 7" Baker Hughes Test Packer. Wait on orders and for 7" Bridge plug. P/U and RIH With Baker Hughes 7" Lock Set Bridge plug. and (41) Joints of (2 7/8") P-110 tubing set Bridge plug at 1300' POOH With (41) Joints of (2 7/8") P-110 Tubing Lay down Retrieving tool. P/U 7" Baker Hughes Test packer and RIH With 22 joints of (2 7/8") P-110 tubing set packer and test from 700' to 1300' test to 700 psi test Test from. (654' to 845' Would not test) (845' to 1300' Test Good) (1300' to 1323' Test Bad). POOH With Test packer. RIH With Retrieving Head and 43 Joints of (2 7/8")P-110 Tubing. Dump 10' of sand on top of bridge plug POOH With tubing. Close in well secure all valves. Pick up all trash clean location.
10/31/2016	Tripped out of hole. Made up retrievable bridge plug and tripped in hole to 6010'.. Attempted to set bridge plug. No good. Tripped out of hole. Made up new bridge plug and tripped in hole to 6010'. Set bridge plug at 6010'. tripped out of hole to kill string.
11/1/2016	POOH standing back in derrick (114) Joints of (2 7/8") P-110 Tubing Lay down retrieving head. Spot in and Rig up Tiger Wire Line. RIH and Shoot holes at (5,970'to 5,980'). POOH Rig out wire line. Pick up 7" Full Bore Packer and RIH With (186) Joints of (2 7/8") P-110 tubing Set packer at (5,913').Spot in and Rig up Halliburton Cement crew. Attempted to establish injection rate. Pumped .08 bbls to 2100 psi. Bled down to 17oo psi. Pressured back up to 2100 psi. No injection rate, formation tight. Unset packer and POOH Standing back in derrick (186) Joints of (2 7/8") P-110 tubing. Pick up and RIH With (6) Joints of (2 7/8") N-80 tubing, 7" Packer and (80) Joints of (2 7/8") P-110 tubing. Close in well secure all valves. Pick up all trash clean location
11/2/2016	RIH With tubing out of derrick (102) Joints of (2 7/8") P-110 tubing. Tag top of sand at (5,987') POOH with 1 joint of tubing and RIH With 10' of Pup Joints. Rig up Hallburton Cement crew. Pressure test lines to (2,500 PSI) Pump 10BBL Of fresh water 4BBL of cement followed by 34bbl of fresh water. POOH With (6) Joints of (2 7/8") P-110 tubing, Reverse circulate Pump 90 Barrels of Polymer fluid. Clean out lines. Rig out Cement crew. Close in well secure all valves. Slip and cut 520' of drill line Pick up all trash clean location and tools.
11/3/2016	Tagged cement at 5946'. Witnessed by DOGGR Emie Blains. Tripped out of hole. Ran full bore packer to 1300'. Established injection rate at 1 bbl/min at 1000 psi.Tripped out of hole. Ran cement ratainer and set at 1300'.

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RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION
DIVISION OF OIL, GAS, AND GEOTHERMAL RESOURCES

HISTORY OF OIL OR GAS WELL

Operator Southern California Gas Company Field Aliso Canyon County Los Angeles
Well Porter 32 Sec 27 3N 16W S.B.B.M.
A.P.I. No. 03700719 Name Tom McMahon (Person submitting report) Title SIMP Project Manager (President, Secretary, or Agent)
Date 3/8/2017 (Month, day, year)
Signature
Address PO Box 2300, SC9365, Chatsworth, CA, 91313-2300 Telephone Number 714-398-5020

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Start Date	Ops this Report (DOGGR)
11/4/2016	Spot in and Rig up Halliburton cement crew. Pressure test lines to (2,500psi) Test good. Pump 4bbl of fresh water, Squeezed away 7bbl of cement followed by 7.5bbl of fresh water at 1 bbm with final circulating pressure of 805 psi. Pull out of cement retainer and reverse circulate clean out tubing. R/O Cement crew. POOH With (41) Joints on (2 7/8") P-110 tubing. Lay down Baker tool. RIH With (26) Joints of (2 7/8") P-110 tubing. Dump 10' of sand on top of cement retainer. Rig up Halliburton Cement Crew. Pump 22 Barrels of cement Cover holes from (845' to 645') POOH With tubing leave 6 Joints of (2 7/8") P-110 Close in well and down squeeze 3 barrels of fresh water with 0 PSI. R/O Halliburton. Close in Well secure all valves. Pick up all trash clean location. Rig up pump Grease and service rig
11/5/2016	RIH with 12 Joints of (2 7/8") P-110 tubing Tag top of cement at (528') POOH laying down 22 Joints of (2 7/8") P-110 tubing. RIH With (6 1/8") Bit, Bit Sub 4 Drill collars, X-over, and 12 joints of (2 7/8") P-110 tubing. Spot in and Rig up Ensign 2.5 Power Swivel. Function test and set torque to (2,500psi). Establish Circulation and drill on Cement from (528') to (851') Using Ensign 2.5 Power Swivel. Tested casing at 700'. Pressure bled down 500 psi to 100 psi in 1 min 45 sec. Tested casing at 851'. 2 bbls/min at 200 psi. Pull High on Power Swivel Close in well secure all valves Pick up all trash clean location
11/7/2016	POOH With 37 Joints of (2 7/8") P-110 tubing Stand back in derrick 4 drill collars and BHA. RIH With (27) Joints of (2 7/8") P-110 tubing. Rig up Halliburton Cement Crew. Pump 25 Barrels of cement Cover holes from (845' to 645') POOH With tubing leave 6 Joints of (2 7/8") P-110 Close in well and down squeeze 11 barrels of fresh water With final pressure of 480 psi. Clise in well. R/O Halliburton. Close in well secure all valves. Pick up all trash clean location
11/8/2016	Tagged cement at 488'. Drilled out cement from 488' to 691', Tested casing to 500 psi. Good Test. Drill out cement from 691' to 755'. Tested casing. No good. Pumping away at 2 bpm with 450 psi. Tripped out of hole. Ran in hole open ended to 755'. Secure well.
11/9/2016	Rig up Halliburton Cement Crew. Pump 24 Barrels (135 cuft) 75sx of cement Cover holes from (755 to 645) POOH With tubing leave 4 Joints of (2 7/8") P-110 Close in well and down squeeze 11 barrels of fresh water with a final circulating pressure of 350 psi. R/O Halliburton. Close in well secure all valves. pick up all trash clean location. Clean Rig and wash out Ensign pump. Wait on cement.
11/10/2016	Tagged cement at 478'. Drilled out cement from 478' to 860'. Tested casing to 500 psi. Tripped in hole to 1300'. Tripped out of the hole to kill string.
11/11/2016	Tripped out of hole. Ran scraper to 1300'. Ran Bond Log from 1300' to surface. Made up Baker Milling assembly and tripped in hole to kill string.
11/14/2016	Wait on orders from DOGGR. Clean rig open well. POOH standing back in derrick (20) Joints of (2 7/8") P-110 tubing Lay down BHA. Dump sand from surface onto Cement retainer dumped (3) 50 Pound bags of sand. Pick up and RIH With 7" Bridge plug, and 32 Joints of (2 7/8") P-110 tubing. Set Bridge plug at (1,000')' POOH With 4 Joints of (2 7/8") P-110 tubing and dump 7-50# Sacks of sand. POOH standing back in derrick (30) Joints of (2 7/8") P-110 tubing. Close in well Secure all valves pick up all trash clean location.

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HISTORY OF OIL OR GAS WELL

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Well Porter 32 Sec 27 3N 16W S.B.B.M.
A.P.I. No. 03700719 Name Tom McMahon (Person submitting report) Title SIMP Project Manager (President, Secretary, or Agent)
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Start Date	Ops this Report (DOGGR)
11/15/2016	Service Rig. Gauge Pressure on Tubing (0psi) and Casing (0psi). Pumped 0 bbls to fill casing. Gauge Tanks 355 bbls of fluid on location. Spot in and Rig up Tiger Wire Line. Shoot holes in casing at (774' to 780') (794' to 800') (844' to 850') (878' to 884') and (890' to 900') R/O Wire line. RIH With (32) Joints of (2 7/8") P-110 tubing Tag top of sand at (980') POOH With 2 Joints and set tubing tail at (949'). Rig up Halliburton Cement Crew. Pump (31) Barrels of cement Cover holes from (774' to 900') POOH With tubing leave 2 Joints of (2 7/8") P-110 Close in well and down squeeze 21 barrels of fresh water with a final circulating pressure of 275 psi.. R/O Halliburton. Close in well secure all valves. Clean location spot in and Rig up king swivel.
11/16/2016	Drilled out cement from 764' to 950'. Ran scraper. Ran CBL from 983' to surface.
11/17/2016	Tripped in hole to 950'. Pumped 32 bbls (180 cu,ft 100 sx) of 14.8 ppg cement. Squeezed awy 35 bbls. fianl circulating pressure of 480 psi. Shut down wait for 1.5 hrs. Pressure bled down to 124 psi and flat lined. Shut down and wait on cement.
11/18/2016	Tripped in hole to 832'. Pumped 29 bbls (162 Cu,ft 90 sx, 2% CC) of 14.8 ppg cement. Tripped out of hole to 60'. Down squeezed 1.8 bbls. Pressure came up to 1000 PSI. Bled down to 220 psi in one hour. Pressured back up to 1000 psi and closed in well. Wait on cement.
11/19/2016	Service Rig. Gauge Pressure on Tubing (0psi) and Casing (0psi). Pumped 0 bbls to fill casing. Gauge Tanks 355 bbls of fluid on location. RIH With tubing and tag top of cement at (134') POOH laying down (18) Joints of (2 7/8") P-110 tubing. Rig up Ensign 2.5 Power Swivel Function test and set torque to 2,000 psi. Establish Circulation and drilled Cement from (134' to 340') "Cement was hard" Circulate 40 Barrels of KCL water down the tubing up the casing to clean out well.
11/21/2016	Drilled out cement from 340' to 755'.
11/22/2016	Drilled out cement from 755'to 983'. Ran scraper. Ran bond log from 983' to surface. Submitted log to DOGGR. Waiting on DOGGR response.
11/28/2016	Wait on DOGGR for BOND log cement results. Clean cement out of pump and half bin.
11/29/2016	Spot in and rig up Western Wire Line shoot holes from (800' to 820') Rig out Wire line. RIH with (27) Joints of (2 7/8") P-110 tubing set tubing tail at (854'). Rig up Halliburton Cement Crew. Pump (12) Barrels of cement Cover holes from (800' to 820') POOH With tubing leave 13 Joints of (2 7/8") P-110. Applied 200 psi on casing. Clsed in well. R/O Halliburton. Wait on Cement to dry. Clean location and Rig
11/30/2016	Tagged cement at 595'. Witnessed by DOGGR Ernie Blevins. Drilled out cement from 595' to 860'. Ran scraper to 1000'. Circulated 2 tubing volumes. Pulled out of hole.
12/1/2016	Retrieved RBP. Milled out cement retainer. Pull to kill string.
12/2/2016	Attempt to POOH with Tubing. Shut in well and wait due to High Winds 40 plus MPH wind on work floor. Close in well. Pick up trash.
12/5/2016	Laid down milling tools. Ran in hole to 5822'. Drillied out cement from 5822' to 5990'. Tripped out of hole. Ran scraper.
12/6/2016	Ran scraper. Circulated hole clean. Tripped out of hole. Tripped in hole. Circulated sand out and retrieved RBP. Tripped out of hole.
12/7/2016	Removed BOP. Removed 7" casing spool. Installed new 7" casing spool. Installed BOP and tested.
12/8/2016	Ran collar locator.

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RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION
DIVISION OF OIL, GAS, AND GEOTHERMAL RESOURCES

HISTORY OF OIL OR GAS WELL

Operator: Southern California Gas Company Field: Aliso Canyon County: Los Angeles
Well: Porter 32 Sec 27 3N 16W S.B.B.M.
A.P.I. No. 03700719 Name: Tom McMahon (Person submitting report) Title: SIMP Project Manager (President, Secretary, or Agent)
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Start Date	Ops this Report (DOGGR)
12/9/2016	Ran string mill gauge run. Made up retrieving tool and ran in hole to 7340'.
12/12/2016	Retrieved RBP. Ran 5" scraper
12/13/2016	Scraped 5" liner. Ran 5" RBP
12/14/2016	Ran 5 1/2" casing
12/15/2016	Ran 5 1/2" casing
12/16/2016	Cemented 5 1/2" casing. Set 5 1/2" slips
12/19/2016	Wait on weather. High winds.
12/20/2016	Wait on weather
12/21/2016	Removed BOP. Installed DSA and tubing spool. Installed BOP and tested.
12/22/2016	Changed out 11" 5M Hydril. Picked up BHA and tripped in hole.
12/27/2016	Wait on weather. High winds. Tested casing to 3625 psi. Witnessed by DOGGR Mark Davis.
12/28/2016	Tripped in hole. Drill out float collar.
12/29/2016	Drilled out shoe track. Tripped out of hole. Made up scraper. Cut and slip drill line
12/30/2016	Ran 5 1/2" scraper. Circulated 2 bottoms up. Pulled out of hole to kill string
1/3/2017	Ran wire line logs.
1/4/2017	Ran USIT log.
1/5/2017	Pulled RBP. Ran 5" scraper
1/6/2017	Pulled scraper. RIH open ended. Clean out liner. Lay down work string
1/9/2017	Lay down tubing
1/10/2017	Rigged up to run completion. Shut down due to weather.
1/13/2017	Ran 2 7/8" comlpetion
1/17/2017	Ran 2 7/8" completion
1/18/2017	Spot packer fluid. Set plug at 7393'. Test casing to 1000psi. Good test. Test tubing to 3700psi. Good test. Both test was witnessed by Mark Davis. Open sleeve.
1/19/2017	Remove BOP. Install production tree. Rig down.

OG103 (6/97/GSR/5M) SUBMIT IN DUPLICATE

CONFIDENTIAL

Ex. I – 47

Due to the large file size, this exhibit is an excerpt. The native file of this document is available upon request.

INFORMATION FOR COMPLIANCE WITH THE CALIFORNIA ENVIRONMENTAL QUALITY ACT OF 1970 (CEQA)

If an environmental document has been prepared by the lead agency, submit a copy of the ***Notice of Determination*** or ***Notice of Exemption*** with this notice. Please note that a CEQA determination by a local jurisdiction, if required, must be complete, or the Division may not issue a permit.

CRITICAL WELL DEFINITION

As defined in the California Code of Regulations, Title 14, Section 1720 (a), "Critical well" means a well within:

(1) 300 feet of the following:
  (A) Any building intended for human occupancy that is not necessary to the operation of the well; or
  (B) Any airport runway.
(2) 100 feet of the following:
  (A) Any dedicated public street, highway or the nearest rail of an operating railway that is in general use;
  (B) Any navigable body of water or watercourse perennially covered by water;
  (C) Any public recreational facility such as a golf course, amusement park, picnic ground, campground or any other area of periodic high-density population; or
  (D) Any officially recognized wildlife preserve.

WELL OPERATIONS REQUIRING BONDING

1. Drilling, redrilling, or deepening any well.
2. Milling out or removing a casing or liner.
3. Running and cementing casing or tubing.
4. Running and cementing liners and inner liners.
5. Perforating casing in a previously unperforated interval for production, injection, testing, observation, or cementing purposes.
6. Drilling out any type of permanent plug.
7. Reentering an abandoned well having no bond.

This form may be printed from the DOGGR website at www.conservation.ca.gov/dog/

Well
Porter 32

API #: 04-037-00719-00
Sec 27, T3N, R16W

Operator: So. California Gas Co.

Lease: Porter
Field: Aliso Canyon
Status: Active Gas Storage
BFW:
USDW:

Ground Elevation: 2079.1' asl
Datum to Ground: 6.92' DF

Spud Date: 6/1/1944
Completion Date: 9/1/1944
Last Rework Date: 1/27/1989

Junk: Remnants of hole opener bits & milled 5" liner that was removed & replaced; milled down to 7850'

13-3/8" TOC Surface

17-1/2" Hole

Surface Casing
13-3/8", 54.5#, J-55
0' - 522'

CMT'D w/ 400 SKS,
Good CMT Returns to Surface

522'

12-1/4" Hole (522' - 2112')

10-5/8" (2112' - 7600')

Inner CSG
5-1/2", 17#, X-Line (See Notes**)
0' - 5440'

7" TOC (per CBL, 11/24/1974) 5330'

Otis XLB PCKR 5440'

Production Casing
7"
0' - 3489' 23#, J-55
3489' - 5238' 23#, N-80
5238' - 6828' 26#, N-80
6828' - 7600' 29#, N-80

CMT'D w/ 400 SKS

7455'

7600'

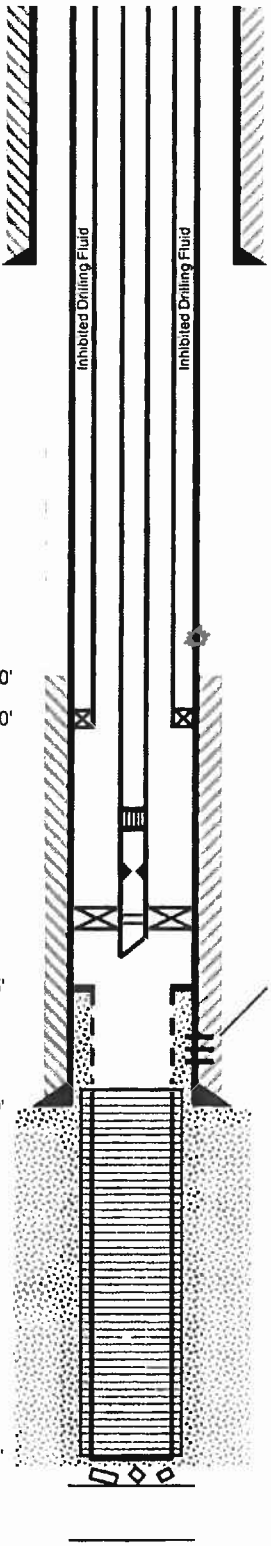
13" Hole (7600' - 7850')

Liner
5" (10/21/1975)
7455' - 7582' 18#, K-55
7582' - 7849' 18#, N-80

7849'

6" Hole (7850' - 7994')

TD 7994'
TVD (7941')
Directionally Drilled: Yes (TD is 304' W, 494' S of Surf)



Tubing
2-3/8", 4.7#, J-55 (1/27/1989)
0' - 7445'

4026' *7" ETOC (After 1st SQZ)

4510' - 4590' 7" CSG Leak (197 CF CMT Calc'd SQZ'D Away*, 9/21/1974 + Addnl 96 CF + 14 CF + 10 CF CMT Calc'd SQZ'D Away btwn. 9/24-28/1974)

7369' Otis XO SSD

7403' Otis XN No-Go Nipple

7438' Baker "D" PCKR (10/27/1975)

7445' Tail

7539' Four (4) 1/2" Holes (Co. WSO, 12/5/1972, 115 CF + 115 CF + 115 CF CMT SQZ'D, 9/9/1975)

7540' Four (4) 1/2" Holes (109 CF CMT SQZ'D Away, 12/1/1972)

7541' Four (4) 1/2" Holes (100 CF CMT SQZ'D Away, 12/3/1972)

7600' (Shoe) WSO

Liner Perfs:
7471' - 7582' 2" x 30M Slots
7582' - 7848' 0.018" Ga. Gru-V-Kut WWS

Gravel Packed w/
239 CF 8-12

7850' Top of Junk (see desc. Above)
CMT Plug @ 7870-7994'
(40 SKS, C/O from 7849')

Notes

4723' - 4732' 59.1% Original Wall Thickness Remaining per Dia-Log Caliper Survey (11/24/1972), 94.7% Original Wall Thickness Remaining per Electronic Casing Inspection Log (11/25/1972)

**5-1/2" inner string run 10/3/74, rerun 11/5/75 & 10/30/79

Top of Zone Markers	md	(tvd)
A36	4741'	(4740')
UP	5063'	(5059')
LP	5543'	(5531')
UDA1	5971'	(5950')
LDA	6798'	(6760')
MP	7275'	(7228')
S1	7523'	(7473')
S4	7616'	(7565')
S8	7723'	(7672')
K1	7978'	(7925')

Prepared by: MAM/CAM (6/9/2016)
Updated by: CAM (7/29/2016)

InterAct

Rec'd 08-01-16 DOGGR Ventura.

Completed Work Summary - Porter 32		
Step	Work Completed	Date
4b	TOC at 5330' per CBL. Log shows good bond from 7500'-7523' (top of S1) and between the MP and S1 from 7310'-7380'.	11/24/1974
5b	Packer set at 7438'.	10/27/1975

Rec'd 08-01-16 DOGGR Ventura.

Casing Pressure Test Safety Check (1000 psi)

Well	Packer Depth MD/TVD	Casing Size/Grade/Weight	Depth MD	Burst PSI	85% of Burst PSI	Pressure at Depth w/1000 psi Surface Pressure	Press < 85% of Burst
Porter 32	7438'/7390'	7", 23#, J-55	3489	4360	3706	2542	Yes
		7", 23#, N-80	5238	6340	5389	3315	Yes
		7", 26#, N-80	6828	7240	6154	4018	Yes
		7", 29#, N-80	7438	8160	6936	4288	Yes
Porter 32A	7160'/7142'	8-5/8", 36#, K-55	5848	4460	3791	3585	Yes
		8-5/8", 36#, N-80	7160	6490	5517	4165	Yes
Porter 39	8400'/8346'	7", 29#, N-80	60	8160	6936	1027	Yes
		7", 23#, J-55	4070	4360	3706	2799	Yes
		7", 23#, N-80	5775	6340	5389	3553	Yes
		7", 26#, N-80	7268	7240	6154	4212	Yes
		7", 29#, N-80	8400	8160	6936	4713	Yes
Fernando Fee 32B	7350'/6863'	8-5/8", 36#, K-55	5863	4460	3791	3591	Yes
		8-5/8", 36#, N-80	6810	6490	5517	4010	Yes
		6-5/8", 28#, K-55*	7350	6970	5925	4249	Yes
Fernando Fee 32D	7032'/7012'	8-5/8", 36#, K-55	5564	4460	3791	3459	Yes
		8-5/8", 36#, N-80	7032	6490	5517	4108	Yes
Fernando Fee 34BR	7350'/7217'	8-5/8", 36#, K-55	7350	4460	3791	4249	No

* Actual pipe in well is a non-API grade so assumed closest size, weight & grade of API pipe

Rec'd 08-01-16 DOGGR Ventura.

Ex. I – 48

HR Vertilog

Magnetic Flux Leakage Inspection

Advanced Analysis

Company	Southern California Gas Company
Well	Porter # 35
Field	Aliso Canyon Storage Pool
County	Los Angeles
State	California
Location:	
Section 27	Township 3N / Range 16W
Date	Feb. 26, 2016
Service Order	US106087
Recorded by	Matthew J Wood
Witnessed by	Mr.Jeff Sandoval
API Serial No.	37-00722

Permanent Datum:	G.L.	Elevation: 2094.000 ft.		Depth	7852.000
Log Measured From:	K.B.	7.000 ft. above Perm. Datum		Btm. Log Interval	7821.140
Drilling Measured From:	K.B.	2101.000 ft. above Perm. Datum		Top Log Interval	21.010
				Fluid Type	Polymer

Casing Data

Size	Weight	Grade	From	To	Length
7 inch	23.0 lb/ft	J55 (HR Std)	0	3351	3351.0
7 inch	23 lb/ft	N-80	3351	5055	1704.0
7 inch	26 lb/ft	N-80	5055	6616	1561.0
7 inch	29 lb/ft	N-80	6616	7910	1294.0
5 inch	18	N-80 Liner	7877	8142	265.0
2.875	N/A	Liner	7851	8134	283.0
13 3/8 inch	55 lb/ft	N/A	0	505	505.0

Equipment Data

Tool	7 to 9-5/8 Inch HRVRT 96 FL + 96 DIS Tool
Magnetizer	7 to 9-5/8 Inch HRVRT 96 FL + 96 DIS Tool
Telemetry	MUX-DB
Software Version	6.0.0.0

Calibration Data

Calibration File Name	4997-7-001-PA10409816-QA10409824.CAL

Date of Calibration	10/14/2014 15:00
Calibration Identifier	F2ECB25B-FBB1-4305-A362-411F79038733
Tool Number	4997-00
Calibrator Number	4997-7-001
Calibrator Size	(7 In - 178 mm)
Calibration Source File	20141015_072957_MEM.MVL
Calibration Software Rev	Microvision 32-bit 7.0.1.0
Comment	RMA1108

Calibration Data

Calibration File Name	4997-7-001-PA10409816-U.CAL
Date of Calibration	04/03/2015 09:27
Calibration Identifier	B7AF82F3-FAAB-4CE0-9570-44283CC7656D
Tool Number	4997-00
Calibrator Number	4997-7-001
Calibrator Size	(7 In - 178 mm)
Calibration Source File	20150403_083948_MEM.MVL
Calibration Software Rev	Microvision 32-bit 7.3.2.2
Comment	RMA1167

Calibration Data

Calibration File Name	4997-7-001-QA10409824-L.CAL
Date of Calibration	04/03/2015 09:27
Calibration Identifier	B7AF82F3-FAAB-4CE0-9570-44283CC7656D
Tool Number	4997-00
Calibrator Number	4997-7-001
Calibrator Size	(7 In - 178 mm)
Calibration Source File	20150403_083948_MEM.MVL
Calibration Software Rev	Microvision 32-bit 7.3.2.2
Comment	RMA1167

In making interpretations of logs our employees will give customer the benefit of their best judgment. But since all interpretations are opinions based on inferences from electrical or other measurements, we cannot, and we do not guarantee the accuracy or correctness of any interpretation. We shall not be liable or responsible for any loss, cost, damages, or expenses whatsoever incurred or sustained by the customer resulting from any interpretation made by any of our employees.

Remarks

Thank you for choosing Baker Hughes Wireline Services.
The tools zero point was at K.B. 7' ABOVE PD.
This log was put on depth with the 56-MFC log of baker hughes 2/26/2016.
N/A Unknown or unavailable at the time of logging.

Interpretation

HRVRT Analysis was depth correlated to Imaging Caliper logged 26 Feb 2016.

The top joint is a short joint.

The HRVRT encountered a high stick and pull through the collars which may result in some collars with reported elongated lengths.

22.04 ft	Hardware - External Casing Head Response.
508.23 ft	Hardware - Bottom of 13 3/8" External Casing.
3355.79 ft	7" Casing Grade change; 23# J55 above, 23# N80 below.
5058.76 ft	7" Casing Weight change; 23# N80 above, 26# N80 below.
6618.99 ft	7" Casing weight change; 26# N80 above, 29# N80 below.

Perforated Interval - Mechanical perforations, Possible Squeezed. Logged from 7808.5' - 7818'. Refer to casing record.

There were no Centralizers or Scratchers observed through the recorded interval.

Joint Interpretation Summary

Joint	From	To	Length	Class	Max Depth	Position	ID/OD
1	21.01	40.96	19.95	Class 1	-	-	-
2	40.96	81.87	40.91	Class 1	-	-	-
3	81.87	124.90	43.03	Class 1	-	-	-
4	124.90	168.01	43.11	Class 1	-	-	-
5	168.01	211.59	43.58	Class 1	-	-	-
6	211.59	254.70	43.11	Class 1	-	-	-
7	254.70	296.99	42.29	Class 1	-	-	-
8	296.99	340.38	43.39	Class 1	-	-	-
9	340.38	384.84	44.46	Class 1	-	-	-
10	384.84	427.41	42.57	Class 1	-	-	-
11	427.41	470.31	42.90	Class 1	-	-	-
12	470.31	513.74	43.43	Class 1	-	-	-
13	513.74	556.71	42.97	Class 1	15.0%	520.39	OD
14	556.71	599.11	42.40	Class 1	-	-	-
15	599.11	640.49	41.38	Class 1	-	-	-
16	640.49	683.90	43.41	Class 1	-	-	-
17	683.90	727.67	43.77	Class 1	-	-	-
18	727.67	770.36	42.69	Class 1	-	-	-
19	770.36	813.89	43.53	Class 1	-	-	-
20	813.89	856.93	43.04	Class 1	-	-	-
21	856.93	900.42	43.49	Class 1	-	-	-
22	900.42	941.64	41.22	Class 1	-	-	-
23	941.64	982.94	41.30	Class 1	18.0%	975.28	ID
24	982.94	1026.73	43.79	Class 1	-	-	-
25	1026.73	1070.27	43.54	Class 1	-	-	-
26	1070.27	1113.17	42.90	Class 1	-	-	-
27	1113.17	1154.67	41.50	Class 1	-	-	-
28	1154.67	1198.20	43.53	Class 1	-	-	-
29	1198.20	1242.45	44.25	Class 1	-	-	-
30	1242.45	1285.60	43.15	Class 1	-	-	-
31	1285.60	1328.28	42.68	Class 1	-	-	-
32	1328.28	1370.30	42.02	Class 1	-	-	-
33	1370.30	1412.43	42.13	Class 1	-	-	-
34	1412.43	1455.48	43.05	Class 1	-	-	-
35	1455.48	1497.95	42.47	Class 1	-	-	-
36	1497.95	1539.17	41.22	Class 1	-	-	-
37	1539.17	1580.93	41.76	Class 1	-	-	-
38	1580.93	1623.27	42.34	Class 1	-	-	-
39	1623.27	1665.75	42.48	Class 1	-	-	-
40	1665.75	1709.09	43.34	Class 1	-	-	-

41	1709.09	1750.83	41.74	Class 1	-	-	-	
42	1750.83	1792.20	41.37	Class 1	-	-	-	
43	1792.20	1835.45	43.25	Class 1	-	-	-	
44	1835.45	1878.84	43.39	Class 1	-	-	-	
45	1878.84	1921.53	42.69	Class 1	-	-	-	
46	1921.53	1963.44	41.91	Class 1	-	-	-	
47	1963.44	2005.74	42.30	Class 1	-	-	-	
48	2005.74	2048.09	42.35	Class 1	-	-	-	
49	2048.09	2089.96	41.87	Class 1	19.0%	2088.30	OD	
50	2089.96	2132.17	42.21	Class 2	20.0%	2124.34	OD	
51	2132.17	2174.87	42.70	Class 2	32.0%	2136.38	OD	
52	2174.87	2215.40	40.53	Class 1	-	-	-	
53	2215.40	2257.84	42.44	Class 1	17.0%	2245.31	OD	
54	2257.84	2300.41	42.57	Class 1	-	-	-	
55	2300.41	2343.13	42.72	Class 1	-	-	-	
56	2343.13	2385.28	42.15	Class 1	-	-	-	
57	2385.28	2427.43	42.15	Class 1	-	-	-	
58	2427.43	2470.50	43.07	Class 1	-	-	-	
59	2470.50	2512.97	42.47	Class 1	-	-	-	
60	2512.97	2554.93	41.96	Class 1	-	-	-	
61	2554.93	2598.39	43.46	Class 1	-	-	-	
62	2598.39	2640.42	42.03	Class 1	-	-	-	
63	2640.42	2679.14	38.72	Class 1	16.0%	2658.25	OD	
64	2679.14	2721.91	42.77	Class 1	-	-	-	
65	2721.91	2764.09	42.18	Class 1	-	-	-	
66	2764.09	2807.06	42.97	Class 1	-	-	-	
67	2807.06	2849.01	41.95	Class 2	21.0%	2826.16	OD	
68	2849.01	2892.27	43.26	Class 1	-	-	-	
69	2892.27	2935.42	43.15	Class 1	-	-	-	
70	2935.42	2977.43	42.01	Class 1	-	-	-	
71	2977.43	3020.33	42.90	Class 2	22.0%	2981.57	OD	
72	3020.33	3062.54	42.21	Class 1	-	-	-	
73	3062.54	3104.90	42.36	Class 1	-	-	-	
74	3104.90	3147.74	42.84	Class 1	15.0%	3116.57	OD	
75	3147.74	3189.72	41.98	Class 1	16.0%	3182.39	OD	
76	3189.72	3231.67	41.95	Class 1	-	-	-	
77	3231.67	3271.32	39.65	Class 1	-	-	-	
78	3271.32	3313.68	42.36	Class 1	-	-	-	
79	3313.68	3355.79	42.11	Class 1	-	-	-	
80	3355.79	3398.13	42.34	Class 4	85.0%	3396.30	OD	anomaly. Fail
81	3398.13	3441.27	43.14	Class 4	86.0%	3420.03	OD	at 3355-3398'.
82	3441.27	3484.13	42.86	Class 4	61.0%	3463.54	OD	
83	3484.13	3526.71	42.58	Class 1	-	-	-	
84	3526.71	3567.80	41.09	Class 1	-	-	-	
85	3567.80	3610.91	43.11	Class 1	-	-	-	
86	3610.91	3651.72	40.81	Class 1	-	-	-	
87	3651.72	3692.53	40.81	Class 1	-	-	-	
88	3692.53	3734.82	42.29	Class 1	-	-	-	
89	3734.82	3777.78	42.96	Class 1	-	-	-	
90	3777.78	3820.15	42.37	Class 1	-	-	-	
91	3820.15	3862.45	42.30	Class 1	-	-	-	
92	3862.45	3906.01	43.56	Class 1	-	-	-	
93	3906.01	3949.54	43.53	Class 1	-	-	-	
94	3949.54	3993.45	43.91	Class 1	-	-	-	
95	3993.45	4034.21	40.76	Class 1	-	-	-	
96	4034.21	4076.87	42.66	Class 1	-	-	-	
97	4076.87	4119.21	42.34	Class 1	-	-	-	
98	4119.21	4163.02	43.81	Class 1	-	-	-	
99	4163.02	4204.61	41.59	Class 1	-	-	-	
100	4204.61	4247.13	42.52	Class 1	-	-	-	
101	4247.13	4289.06	41.93	Class 1	-	-	-	
102	4289.06	4331.91	42.85	Class 1	-	-	-	
103	4331.91	4375.23	43.32	Class 1	-	-	-	

104	4375.23	4414.79	39.56	Class 1	-	-	-
105	4414.79	4458.32	43.53	Class 1	-	-	-
106	4458.32	4501.90	43.58	Class 1	-	-	-
107	4501.90	4545.14	43.24	Class 1	-	-	-
108	4545.14	4585.85	40.71	Class 1	-	-	-
109	4585.85	4628.75	42.90	Class 1	-	-	-
110	4628.75	4671.20	42.45	Class 1	-	-	-
111	4671.20	4714.13	42.93	Class 1	-	-	-
112	4714.13	4757.35	43.22	Class 1	-	-	-
113	4757.35	4800.25	42.90	Class 1	-	-	-
114	4800.25	4843.64	43.39	Class 1	-	-	-
115	4843.64	4885.03	41.39	Class 1	-	-	-
116	4885.03	4929.40	44.37	Class 1	-	-	-
117	4929.40	4973.68	44.28	Class 1	-	-	-
118	4973.68	5015.12	41.44	Class 1	-	-	-
119	5015.12	5058.76	43.64	Class 1	15.0%	5047.02	OD
120	5058.76	5101.23	42.47	Class 1	-	-	-
121	5101.23	5144.50	43.27	Class 1	-	-	-
122	5144.50	5187.05	42.55	Class 1	-	-	-
123	5187.05	5230.38	43.33	Class 1	-	-	-
124	5230.38	5274.73	44.35	Class 1	-	-	-
125	5274.73	5317.03	42.30	Class 1	-	-	-
126	5317.03	5360.74	43.71	Class 1	16.0%	5358.34	ID
127	5360.74	5404.43	43.69	Class 1	-	-	-
128	5404.43	5438.33	33.90	Class 1	-	-	-
129	5438.33	5481.50	43.17	Class 1	-	-	-
130	5481.50	5525.55	44.05	Class 1	-	-	-
131	5525.55	5567.60	42.05	Class 1	-	-	-
132	5567.60	5602.76	35.16	Class 1	-	-	-
133	5602.76	5646.45	43.69	Class 1	-	-	-
134	5646.45	5688.17	41.72	Class 1	-	-	-
135	5688.17	5728.63	40.46	Class 1	-	-	-
136	5728.63	5773.47	44.84	Class 1	-	-	-
137	5773.47	5811.29	37.82	Class 1	15.0%	5809.12	ID
138	5811.29	5853.37	42.08	Class 1	-	-	-
139	5853.37	5896.22	42.85	Class 1	-	-	-
140	5896.22	5940.29	44.07	Class 1	-	-	-
141	5940.29	5982.72	42.43	Class 1	-	-	-
142	5982.72	6026.16	43.44	Class 2	21.0%	6024.23	ID
143	6026.16	6067.41	41.25	Class 1	-	-	-
144	6067.41	6109.27	41.86	Class 1	-	-	-
145	6109.27	6152.20	42.93	Class 1	16.0%	6150.03	ID
146	6152.20	6193.96	41.76	Class 1	18.0%	6191.30	ID
147	6193.96	6237.44	43.48	Class 1	-	-	-
148	6237.44	6279.45	42.01	Class 1	-	-	-
149	6279.45	6321.90	42.45	Class 1	-	-	-
150	6321.90	6364.59	42.69	Class 1	-	-	-
151	6364.59	6407.91	43.32	Class 1	-	-	-
152	6407.91	6452.41	44.50	Class 1	-	-	-
153	6452.41	6495.07	42.66	Class 1	-	-	-
154	6495.07	6536.03	40.96	Class 1	-	-	-
155	6536.03	6577.82	41.79	Class 1	-	-	-
156	6577.82	6618.99	41.17	Class 1	-	-	-
157	6618.99	6661.42	42.43	Class 1	-	-	-
158	6661.42	6699.15	37.73	Class 1	-	-	-
159	6699.15	6735.69	36.54	Class 1	-	-	-
160	6735.69	6774.12	38.43	Class 1	-	-	-
161	6774.12	6809.39	35.27	Class 1	-	-	-
162	6809.39	6851.66	42.27	Class 1	-	-	-
163	6851.66	6895.35	43.69	Class 1	-	-	-
164	6895.35	6938.38	43.03	Class 1	-	-	-
165	6938.38	6982.42	44.04	Class 1	-	-	-
166	6982.42	7024.99	42.57	Class 1	-	-	-
167	7024.99	7067.73	42.74	Class 1	-	-	-

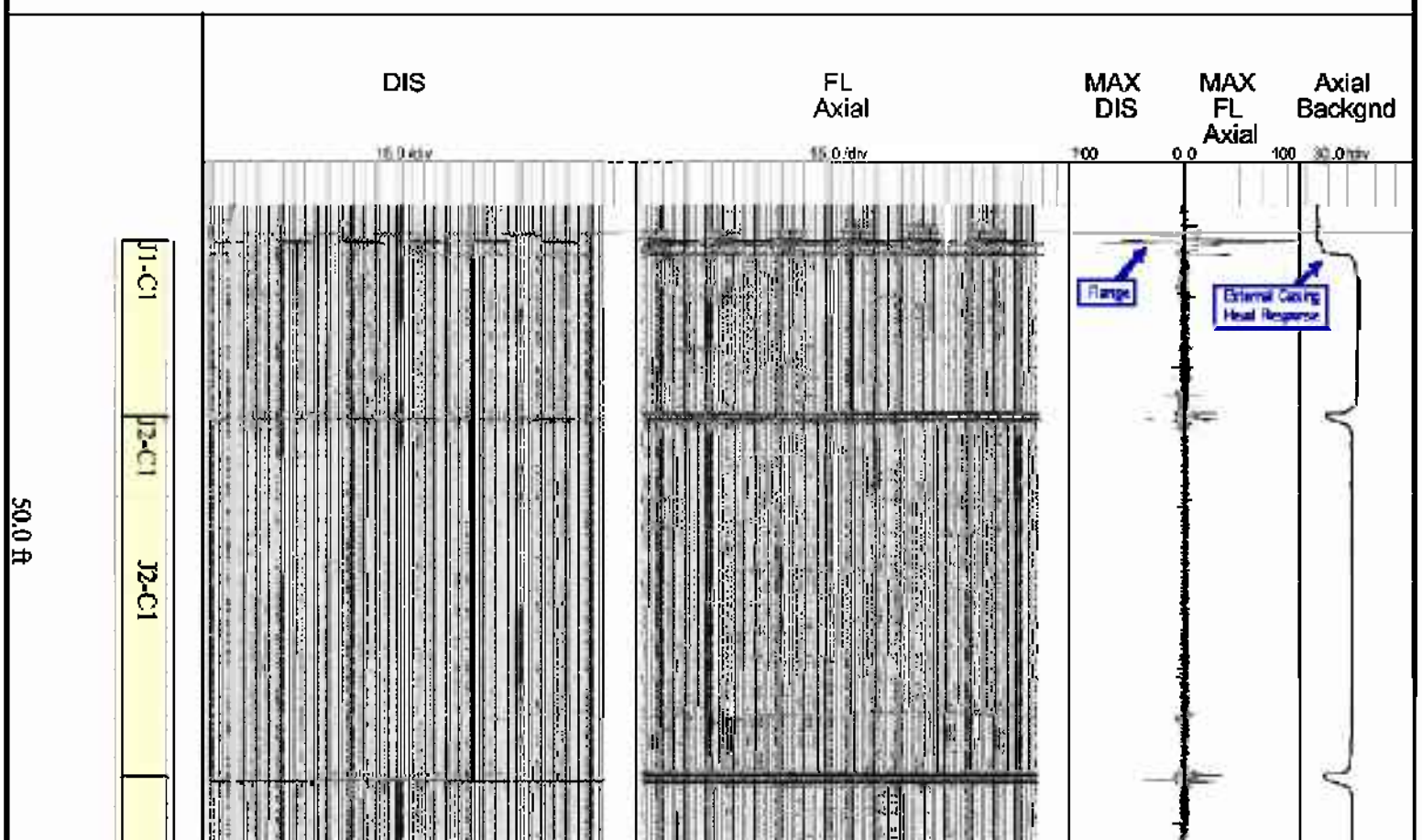
168	7067.73	7110.01	42.28	Class 1	-	-	-
169	7110.01	7150.56	40.55	Class 1	-	-	-
170	7150.56	7193.90	43.34	Class 1	-	-	-
171	7193.90	7237.19	43.29	Class 1	-	-	-
172	7237.19	7270.75	33.56	Class 1	-	-	-
173	7270.75	7315.45	44.70	Class 1	-	-	-
174	7315.45	7356.90	41.45	Class 1	-	-	-
175	7356.90	7401.53	44.63	Class 1	-	-	-
176	7401.53	7444.88	43.35	Class 1	-	-	-
177	7444.88	7485.03	40.15	Class 1	-	-	-
178	7485.03	7527.41	42.38	Class 1	-	-	-
179	7527.41	7569.33	41.92	Class 1	-	-	-
180	7569.33	7613.27	43.94	Class 1	-	-	-
181	7613.27	7656.20	42.93	Class 1	-	-	-
182	7656.20	7699.61	43.41	Class 1	-	-	-
183	7699.61	7742.57	42.96	Class 2	27.0%	7727.40	ID
184	7742.57	7785.74	43.17	Class 1	-	-	-
185	7785.74	7821.14	35.40	Class 1	19.0%	7787.06	ID

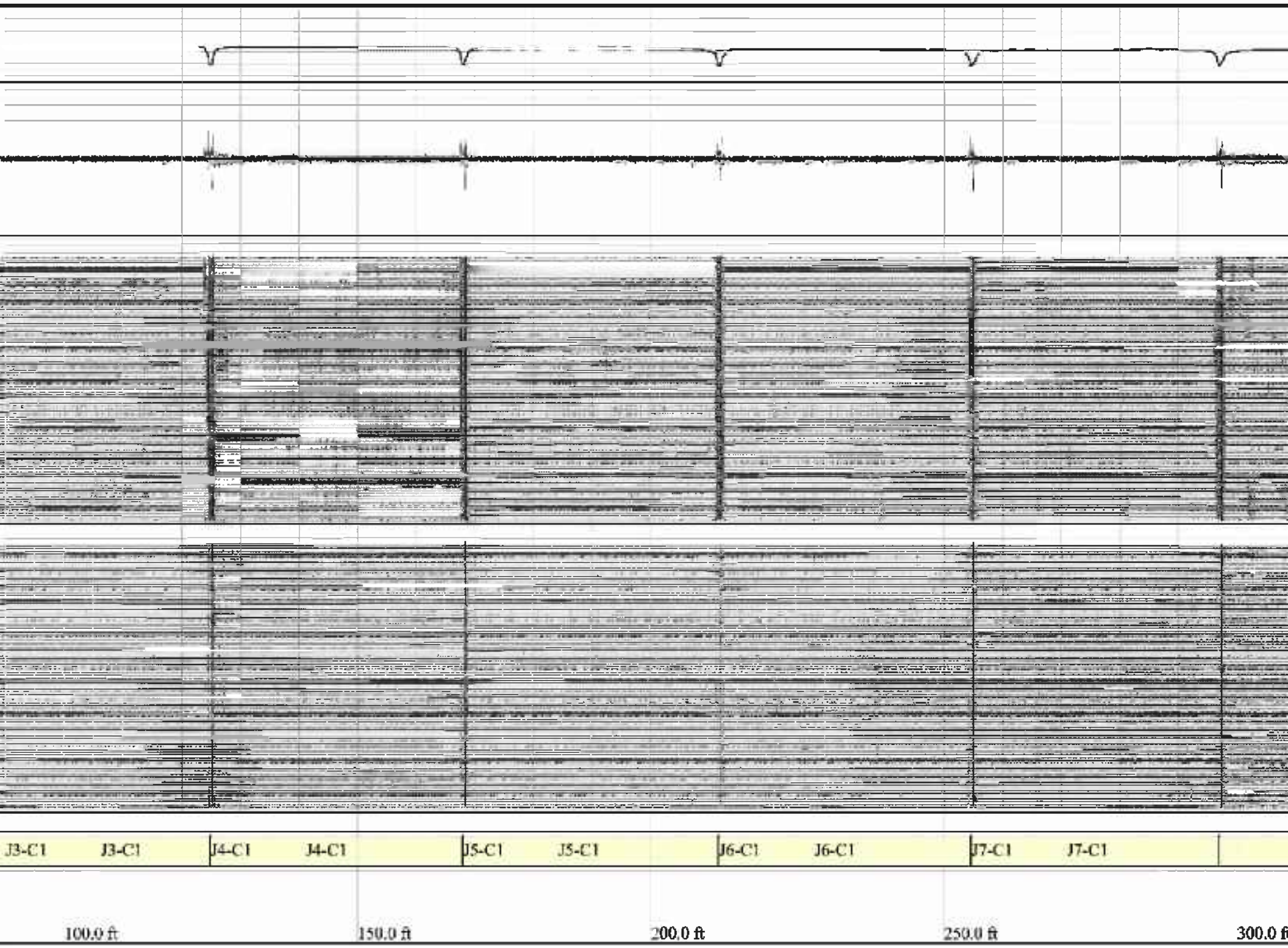
Southern California Gas Company Porter # 35

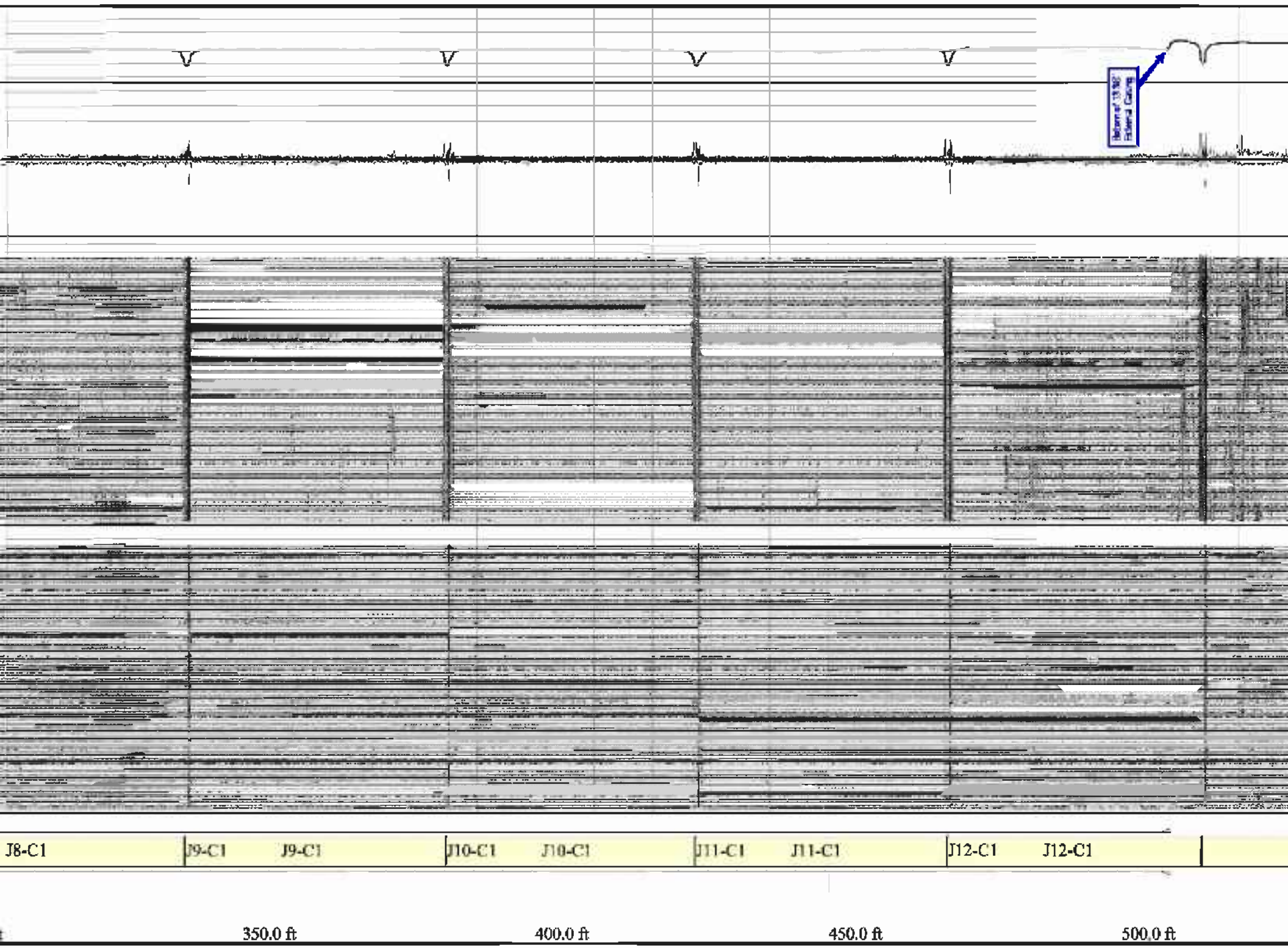
File 20160226_161504_RSP_0_0_0_0_0.mvl

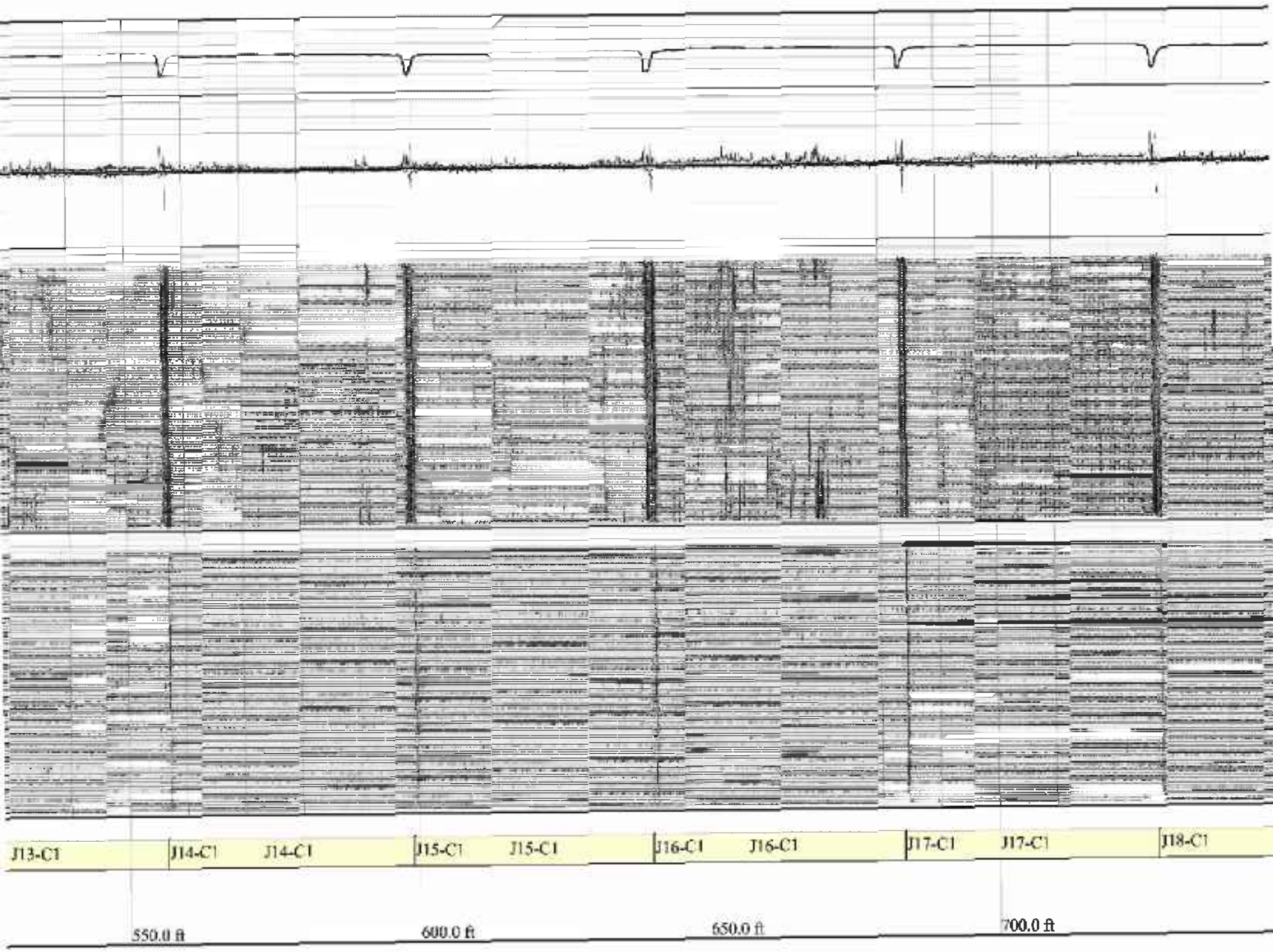
Main Log
5" / 100'

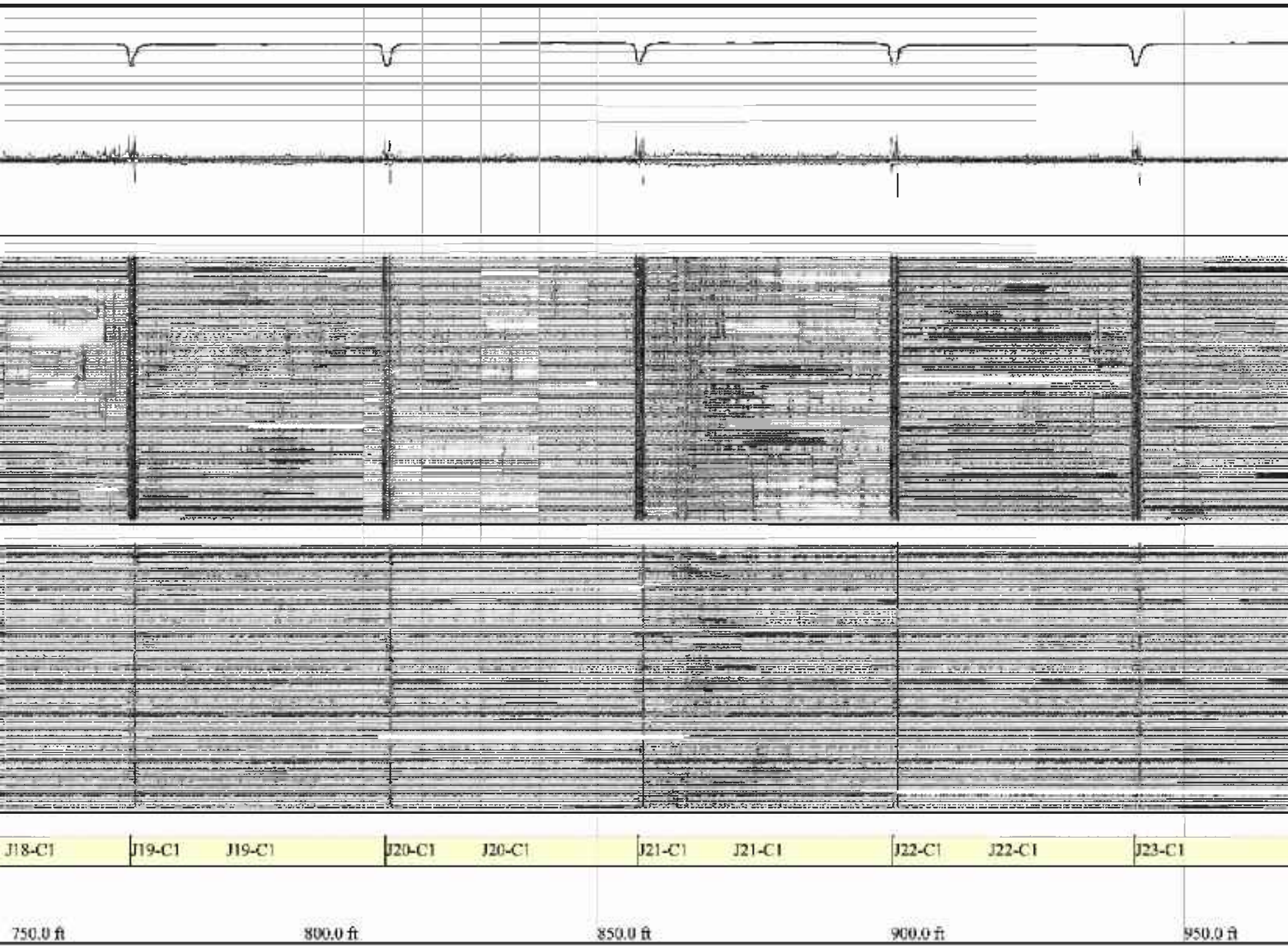
Class 1	Class 2	Class 3	Class 4
0 - 20%	20 - 40%	40 - 60%	60 - 100%

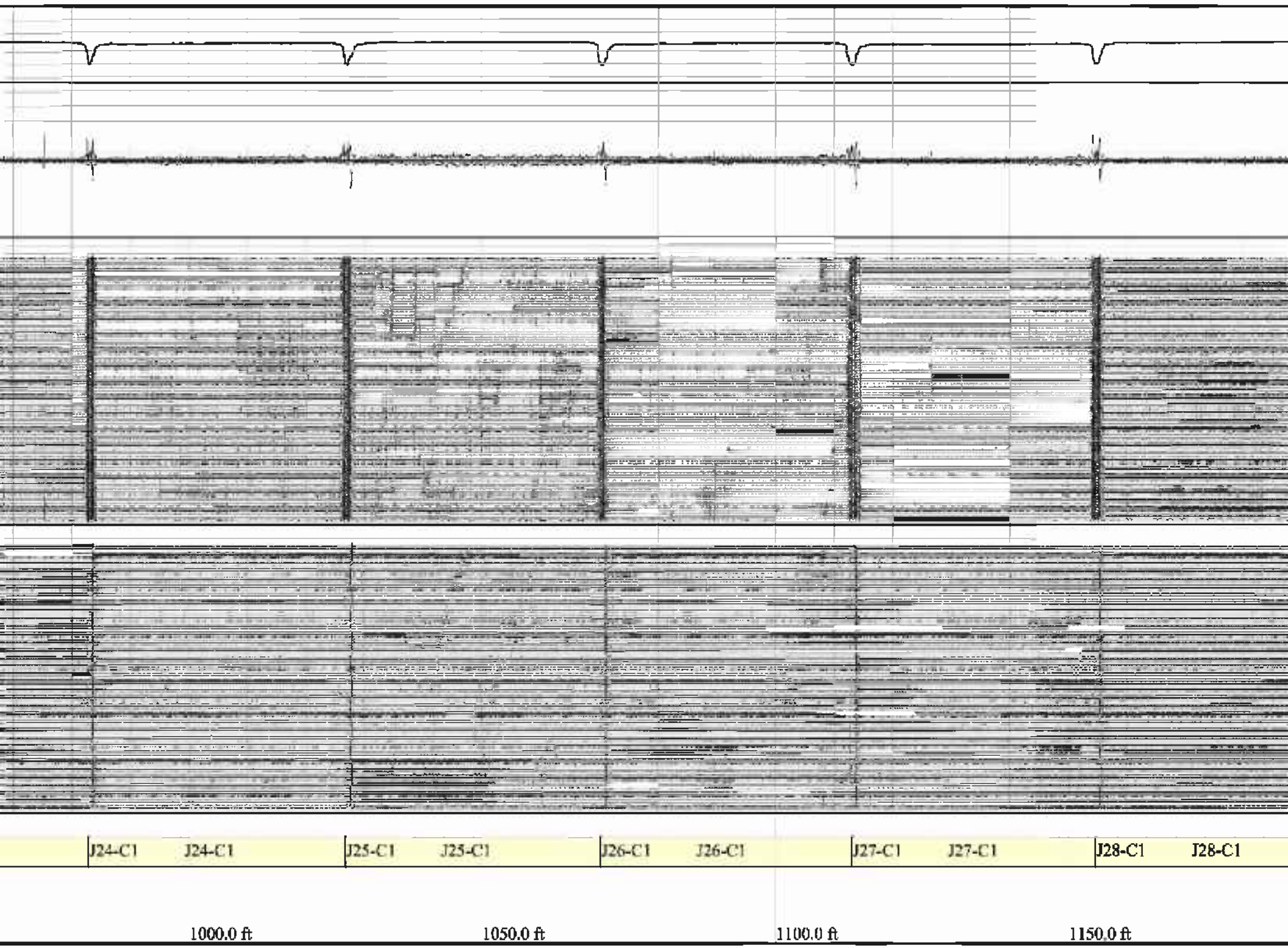


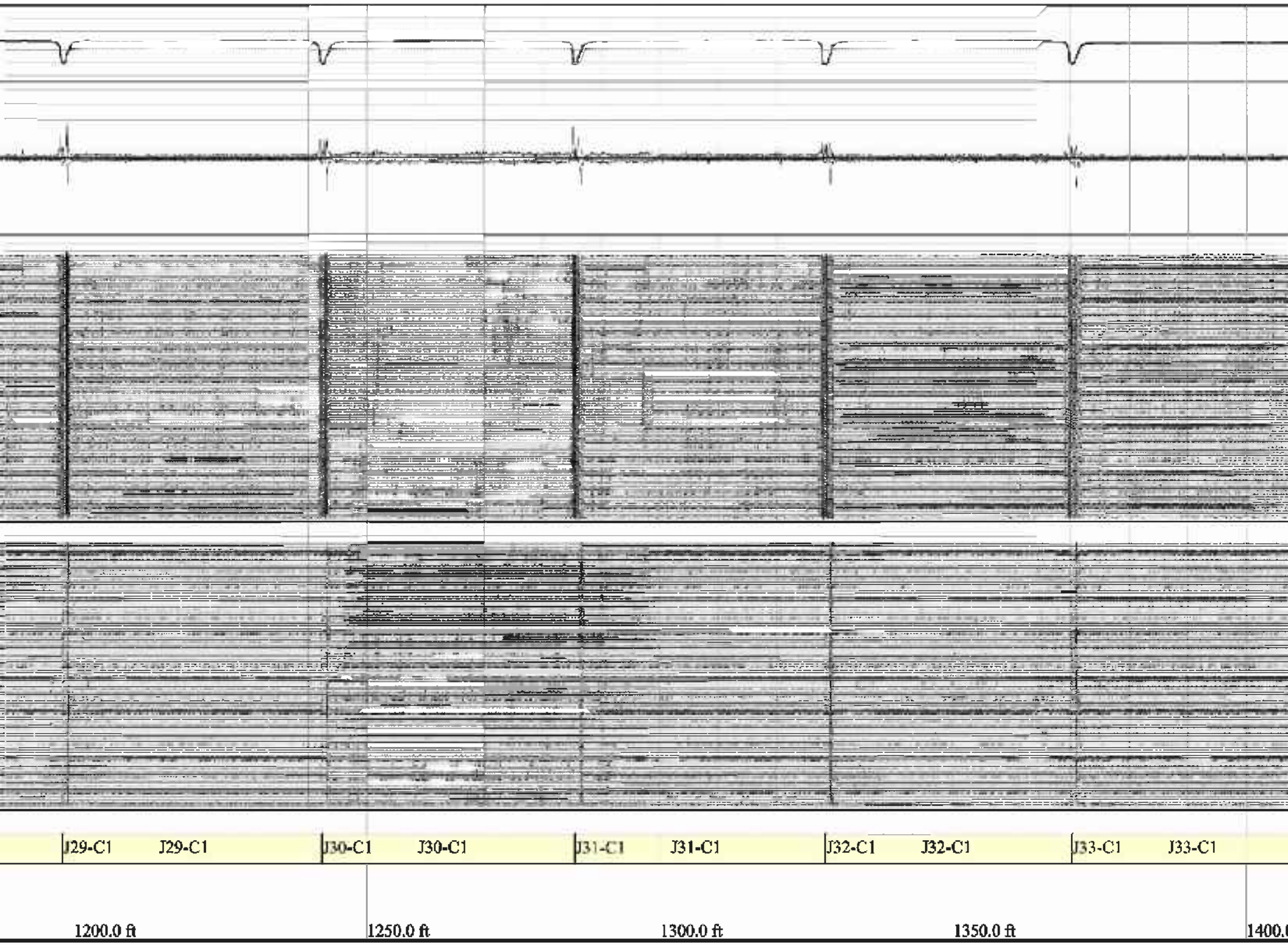

J3-C1
J3-C1
J4-C1
J4-C1
J5-C1
J5-C1
J6-C1
J6-C1
J7-C1
J7-C1
100.0 ft
150.0 ft
200.0 ft
250.0 ft
300.0 f

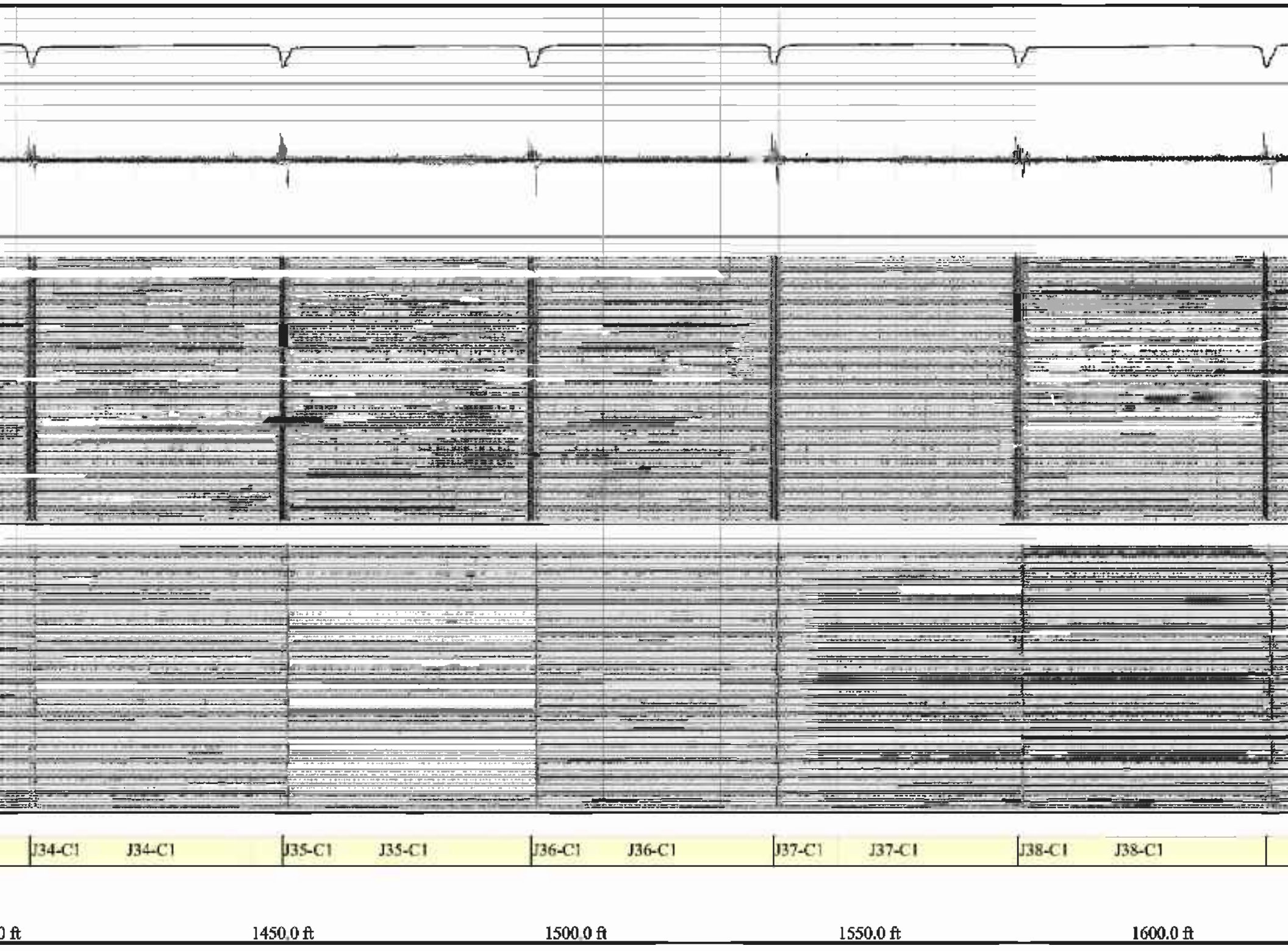

Reference 13.98'
Referral Casing
J8-C1
J9-C1
J9-C1
J10-C1
J10-C1
J11-C1
J11-C1
J12-C1
J12-C1
350.0 ft
400.0 ft
450.0 ft
500.0 ft

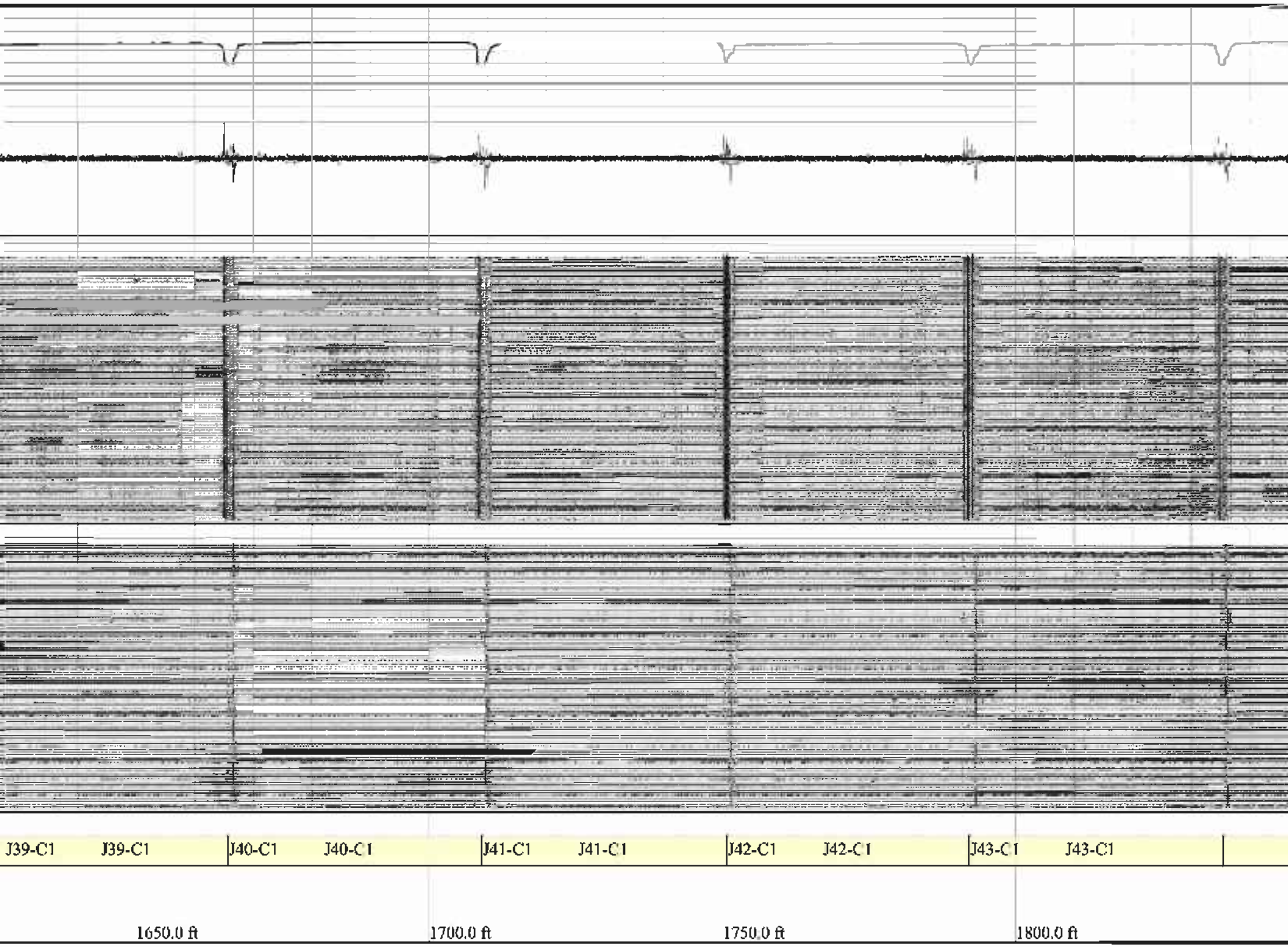

J13-C1
J14-C1
J14-C1
J15-C1
J15-C1
J16-C1
J16-C1
J17-C1
J17-C1
J18-C1
550.0 ft
600.0 ft
650.0 ft
700.0 ft

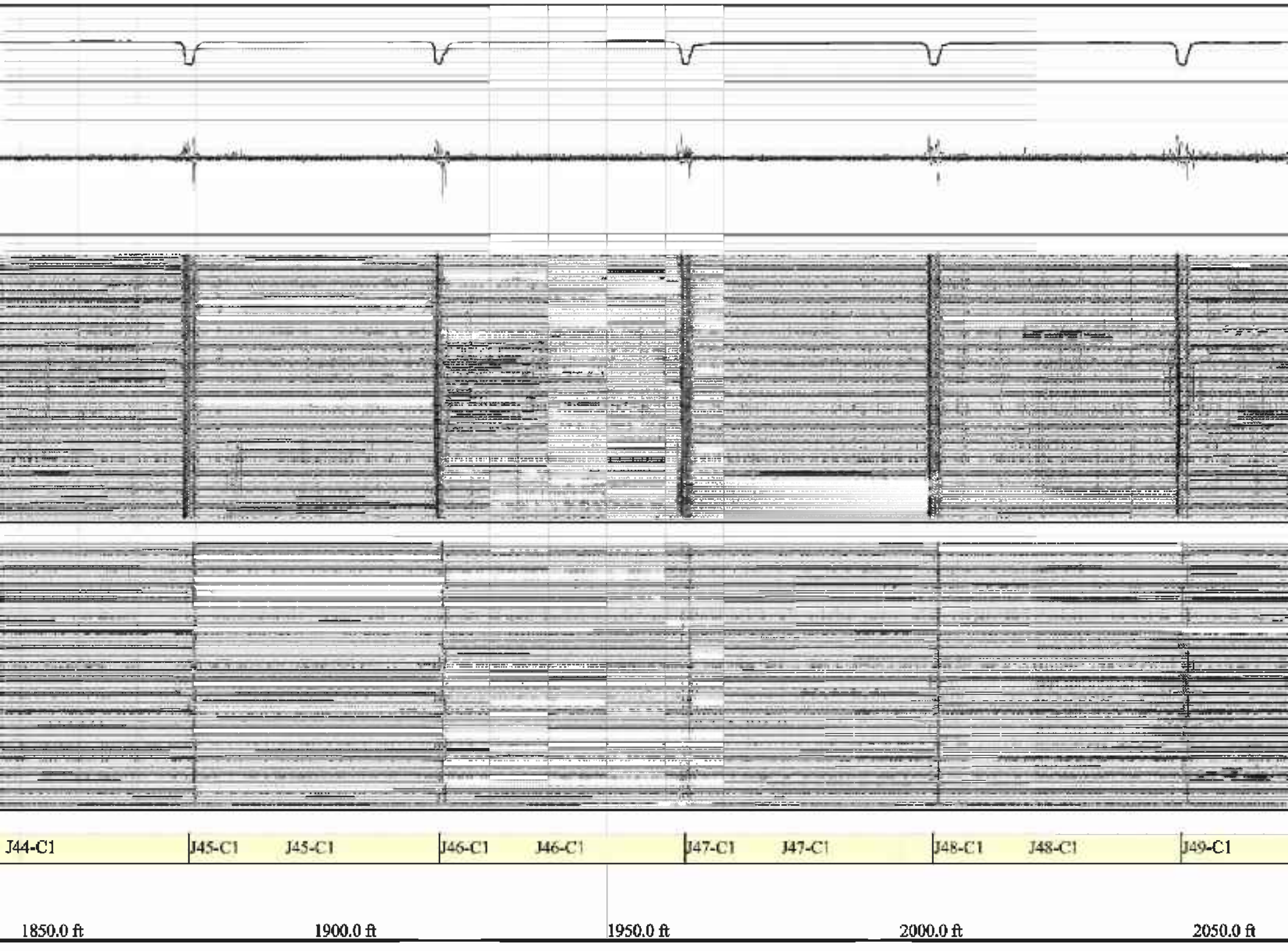

J18-C1
J19-C1
J19-C1
J20-C1
J20-C1
J21-C1
J21-C1
J22-C1
J22-C1
J23-C1
750.0 ft
800.0 ft
850.0 ft
900.0 ft
950.0 ft

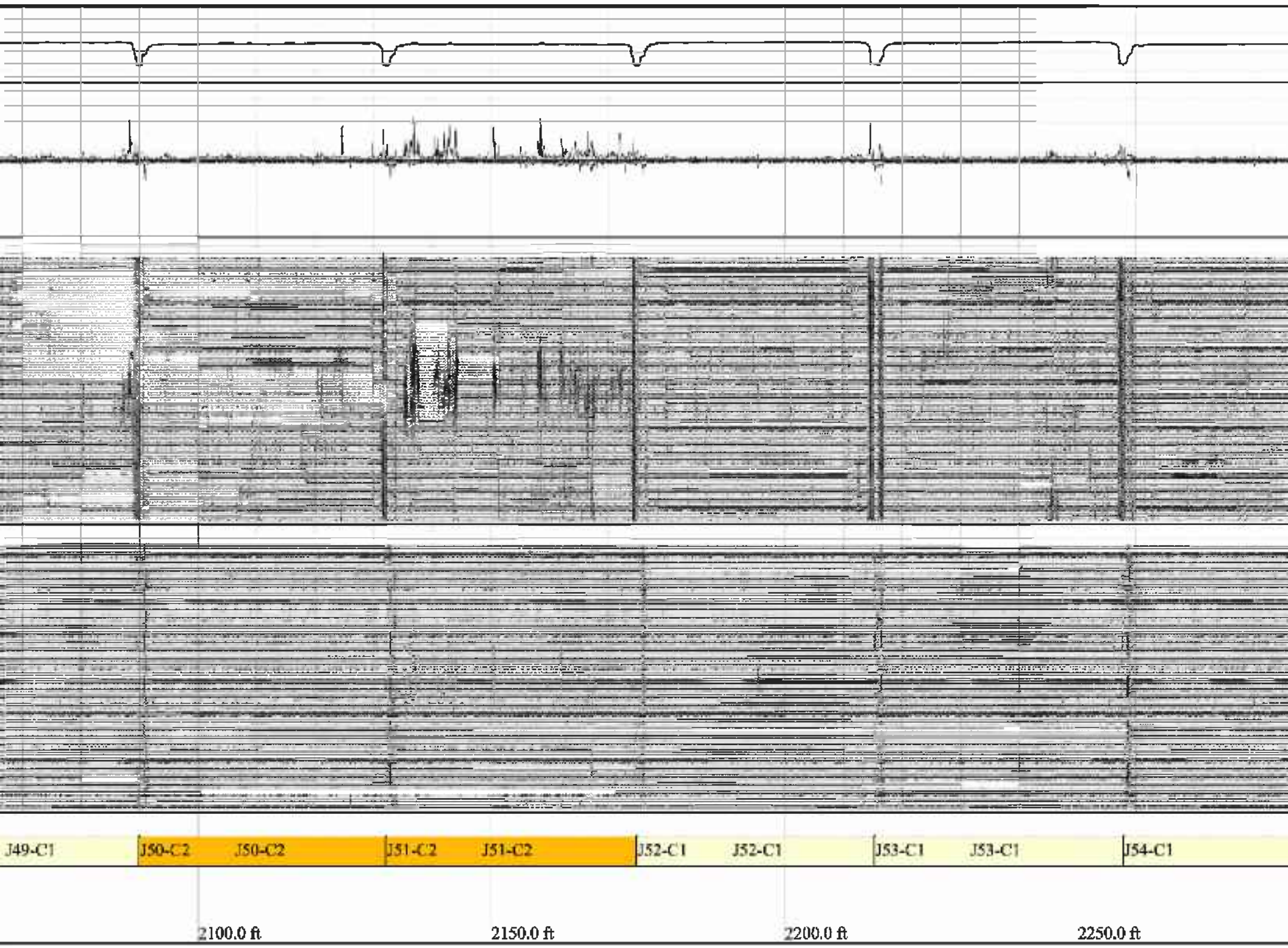

J24-C1
J24-C1
J25-C1
J25-C1
J26-C1
J26-C1
J27-C1
J27-C1
J28-C1
J28-C1
1000.0 ft
1050.0 ft
1100.0 ft
1150.0 ft

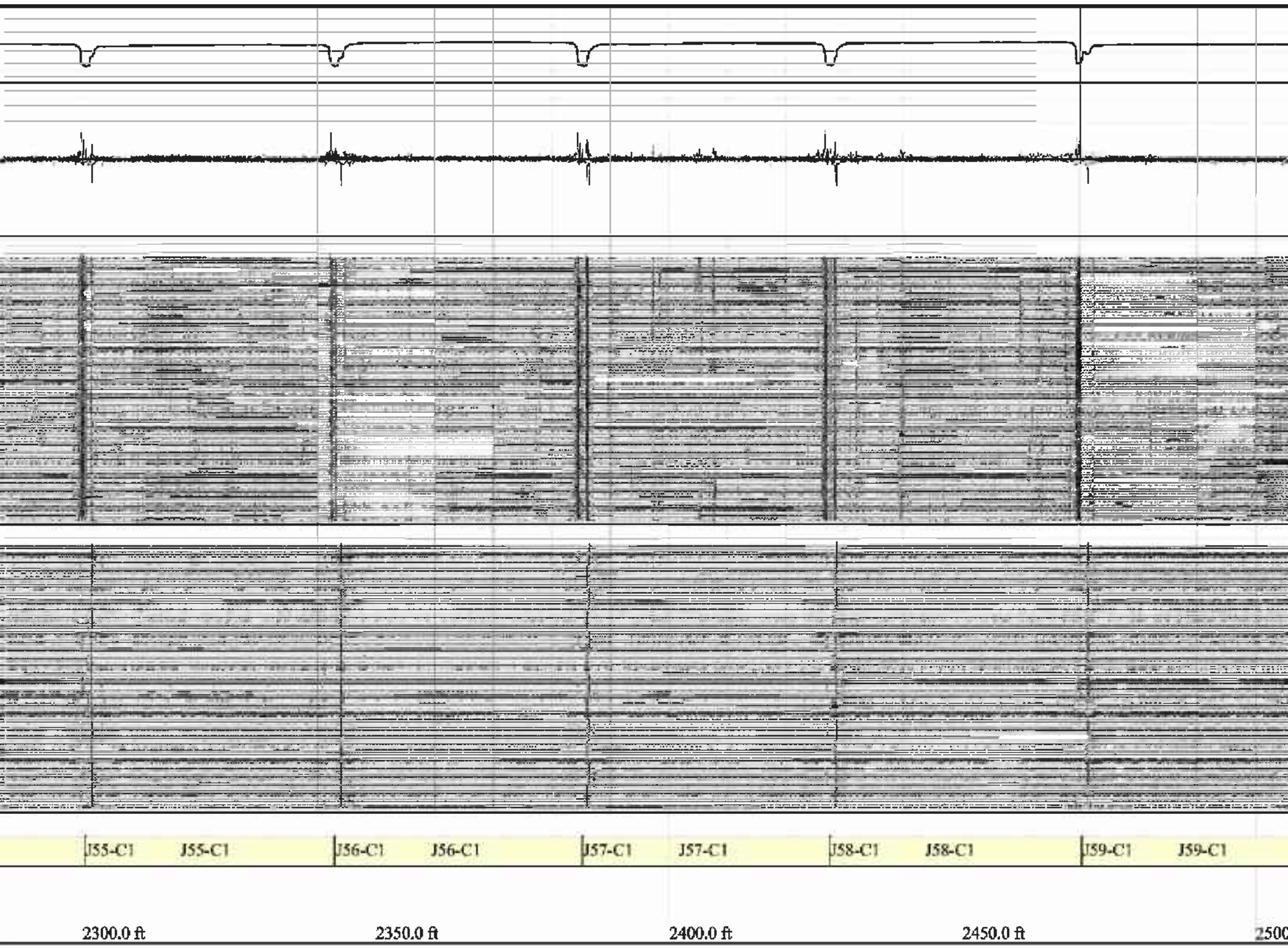

J29-C1
J29-C1
J30-C1
J30-C1
J31-C1
J31-C1
J32-C1
J32-C1
J33-C1
J33-C1
1200.0 ft
1250.0 ft
1300.0 ft
1350.0 ft

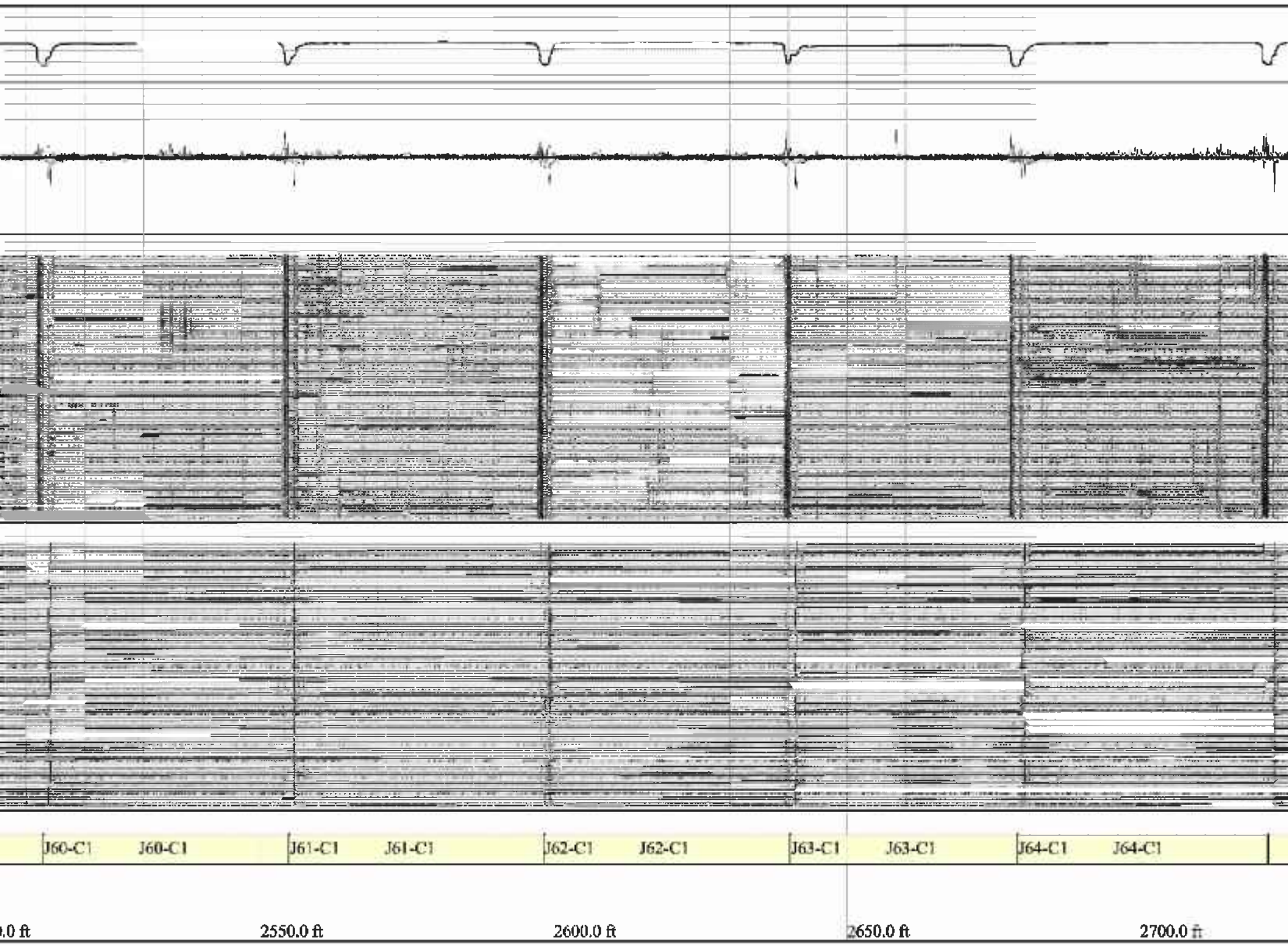

J34-C1
J34-C1
J35-C1
J35-C1
J36-C1
J36-C1
J37-C1
J37-C1
J38-C1
J38-C1
0 ft
1450.0 ft
1500.0 ft
1550.0 ft
1600.0 ft

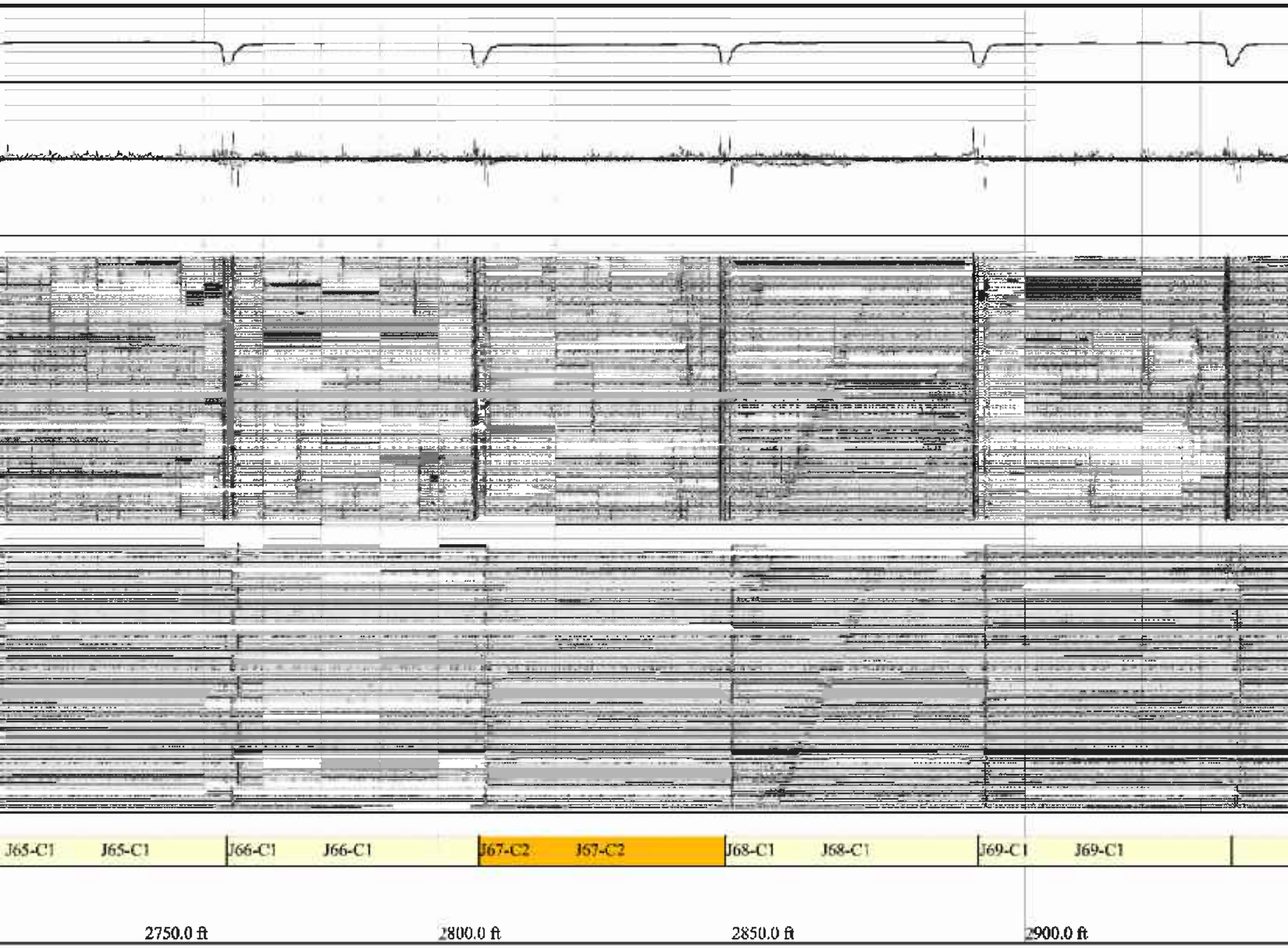

J39-C1
J39-C1
J40-C1
J40-C1
J41-C1
J41-C1
J42-C1
J42-C1
J43-C1
J43-C1
1650.0 ft
1700.0 ft
1750.0 ft
1800.0 ft

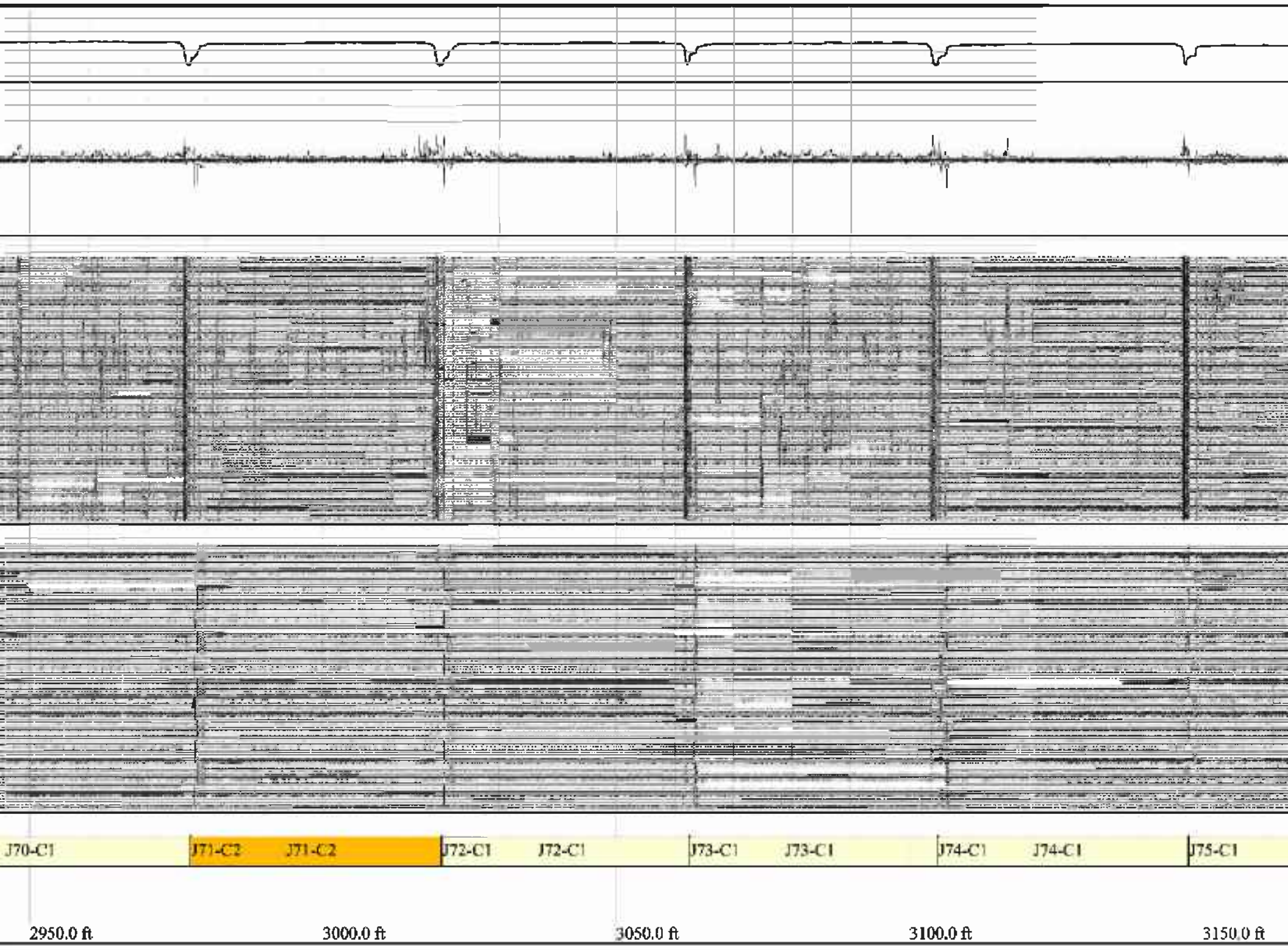

J44-C1
J45-C1
J45-C1
J46-C1
J46-C1
J47-C1
J47-C1
J48-C1
J48-C1
J49-C1
1850.0 ft
1900.0 ft
1950.0 ft
2000.0 ft
2050.0 ft

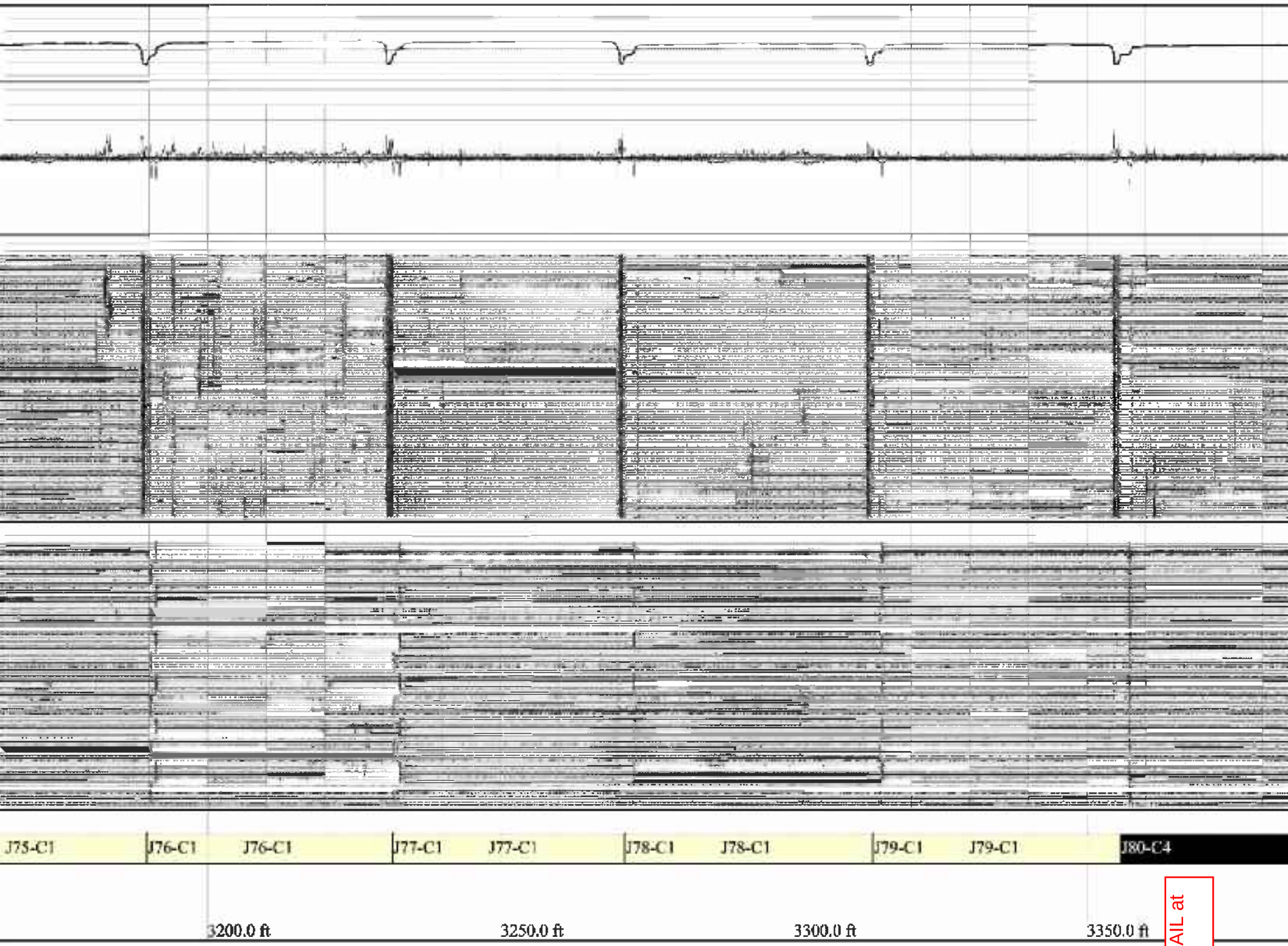

J49-C1
J50-C2
J50-C2
J51-C2
J51-C2
J52-C1
J52-C1
J53-C1
J53-C1
J54-C1
2100.0 ft
2150.0 ft
2200.0 ft
2250.0 ft

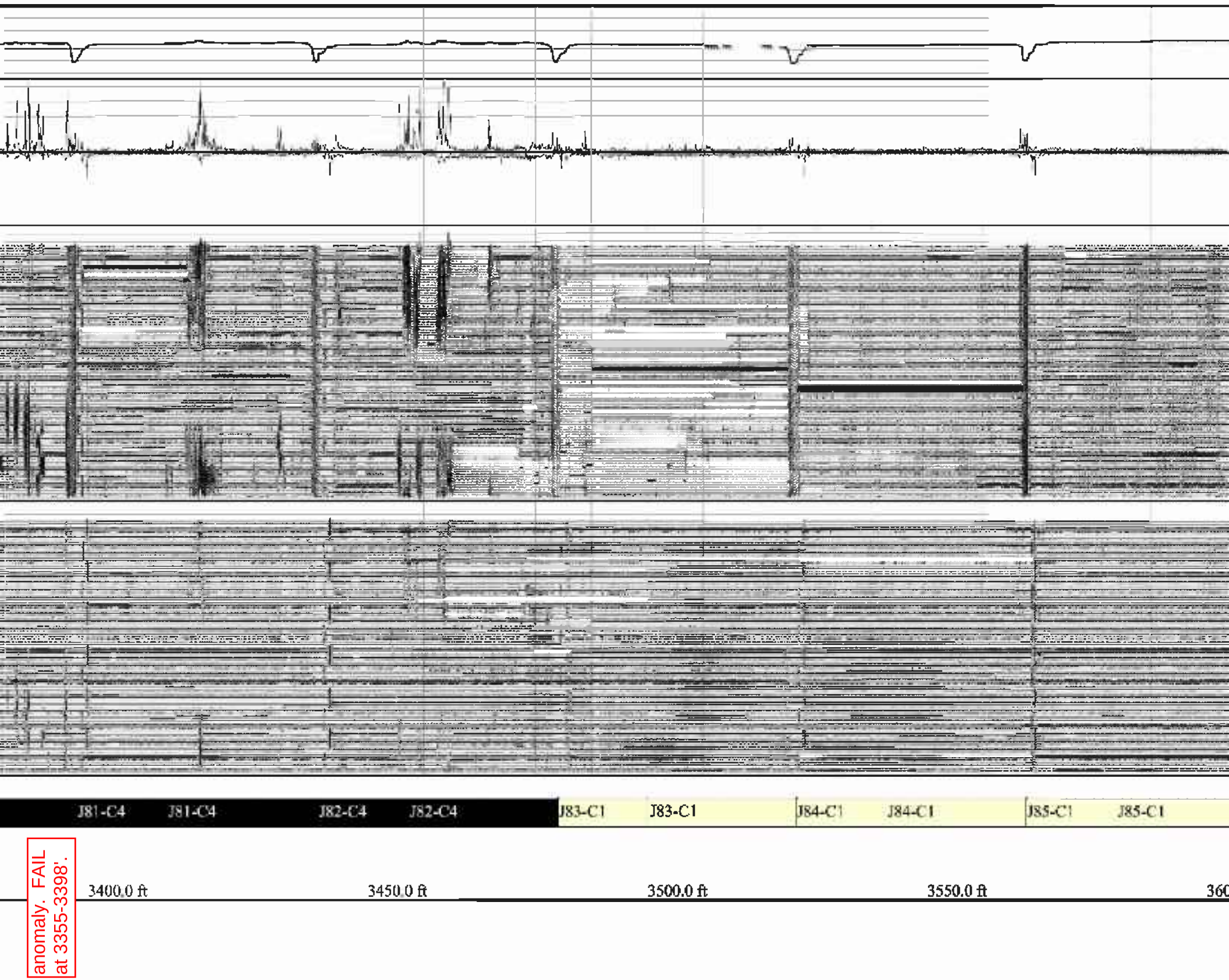

J55-C1
J55-C1
J56-C1
J56-C1
J57-C1
J57-C1
J58-C1
J58-C1
J59-C1
J59-C1
2300.0 ft
2350.0 ft
2400.0 ft
2450.0 ft


J60-C1
J60-C1
J61-C1
J61-C1
J62-C1
J62-C1
J63-C1
J63-C1
J64-C1
J64-C1
.0 ft
2550.0 ft
2600.0 ft
2650.0 ft
2700.0 ft

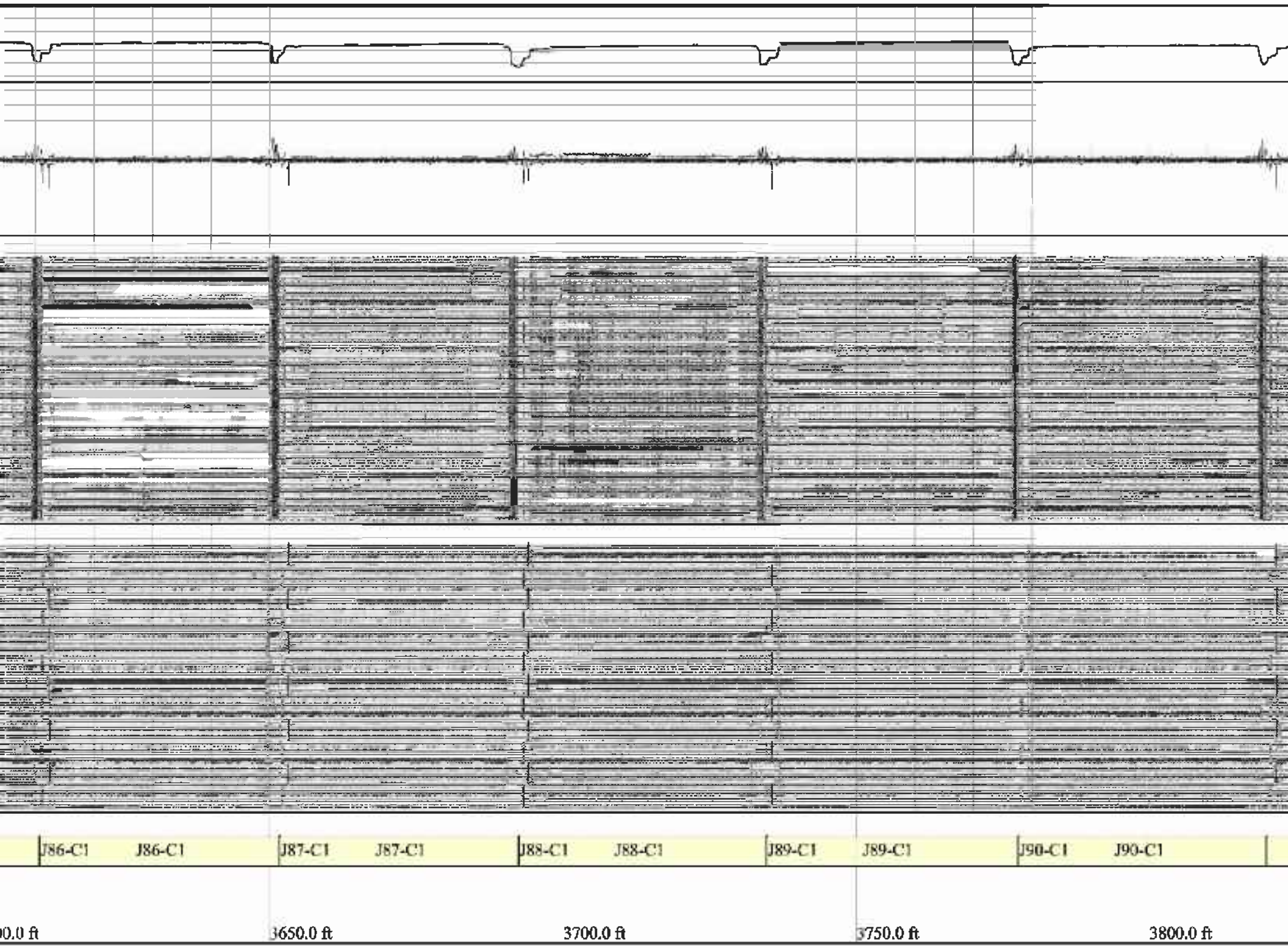

J65-C1
J65-C1
J66-C1
J66-C1
J67-C2
J67-C2
J68-C1
J68-C1
J69-C1
J69-C1
2750.0 ft
2800.0 ft
2850.0 ft
2900.0 ft

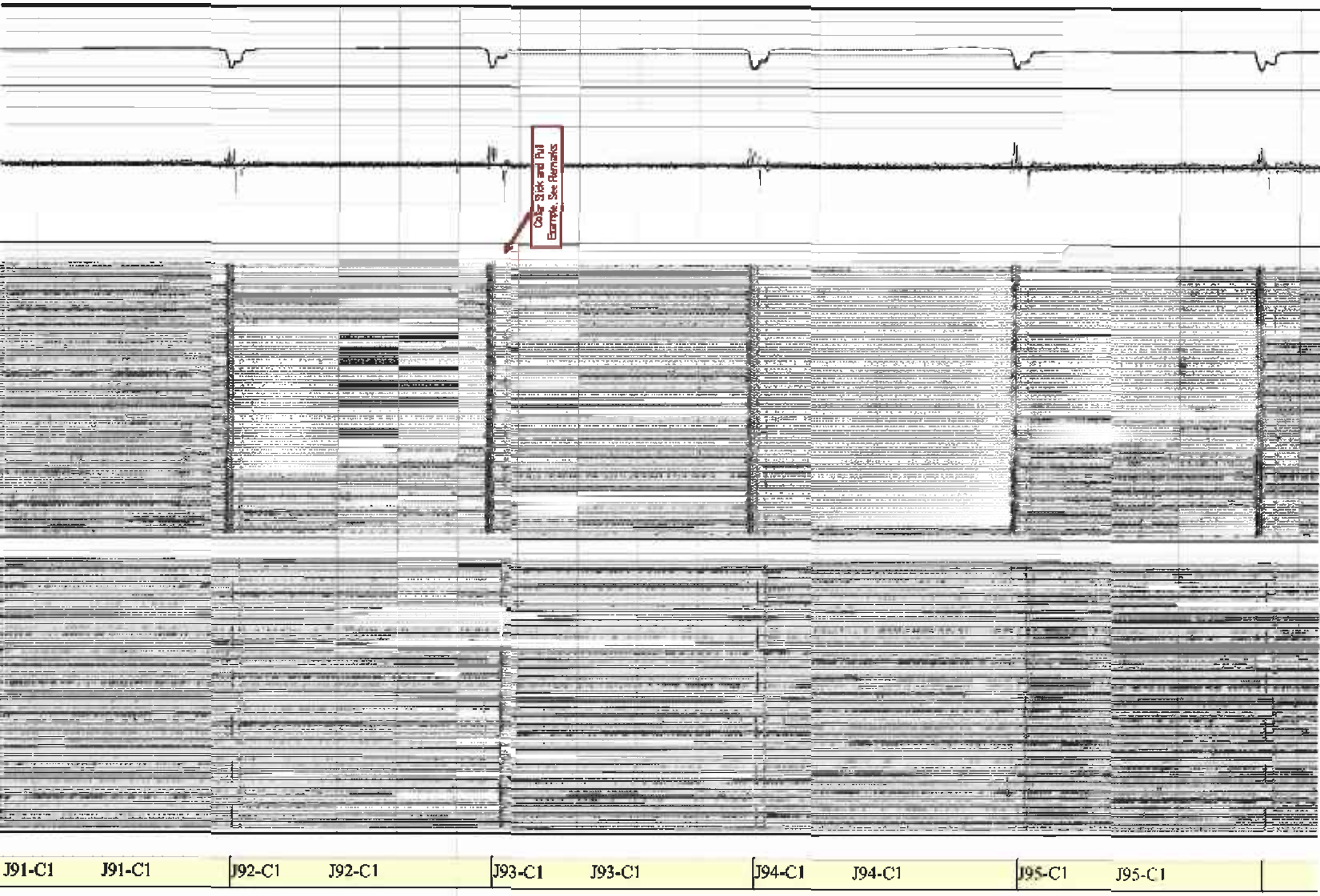

J70-C1
J71-C2
J71-C2
J72-C1
J72-C1
J73-C1
J73-C1
J74-C1
J74-C1
J75-C1
2950.0 ft
3000.0 ft
3050.0 ft
3100.0 ft
3150.0 ft

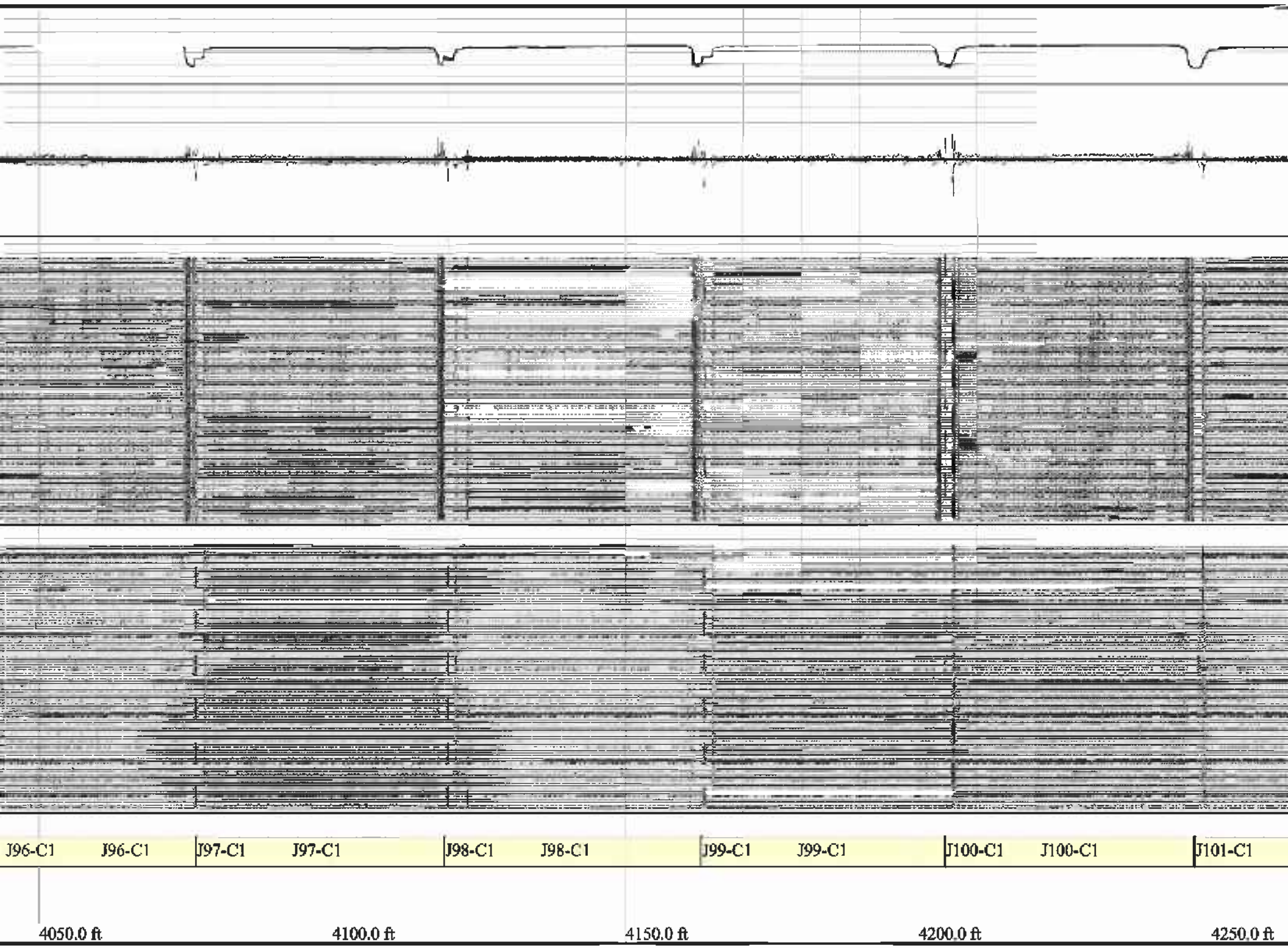

J75-C1
J76-C1
J76-C1
J77-C1
J77-C1
J78-C1
J78-C1
J79-C1
J79-C1
J80-C4
3200.0 ft
3250.0 ft
3300.0 ft
3350.0 ft
anomaly. FAIL at 3355-3398'

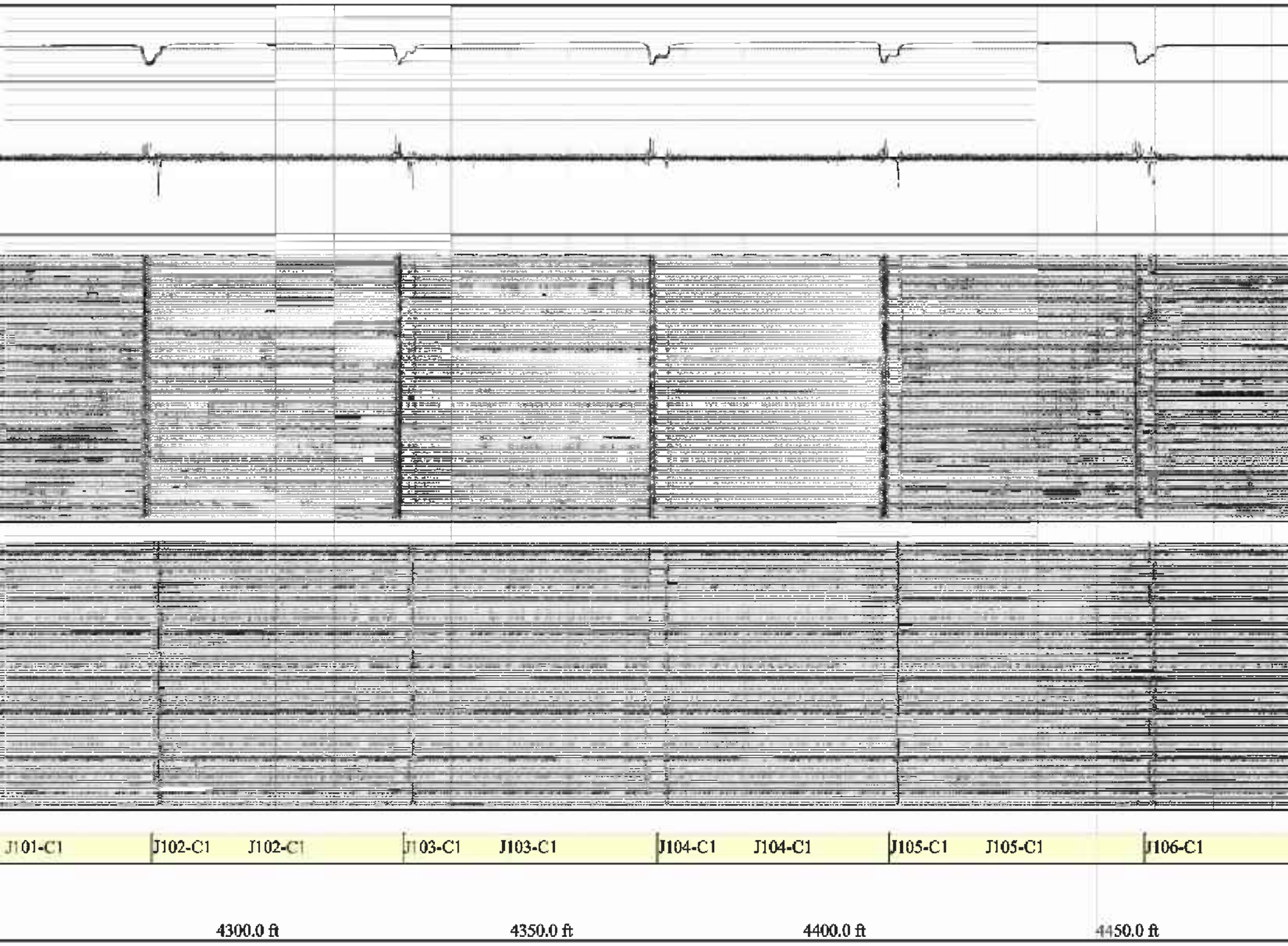


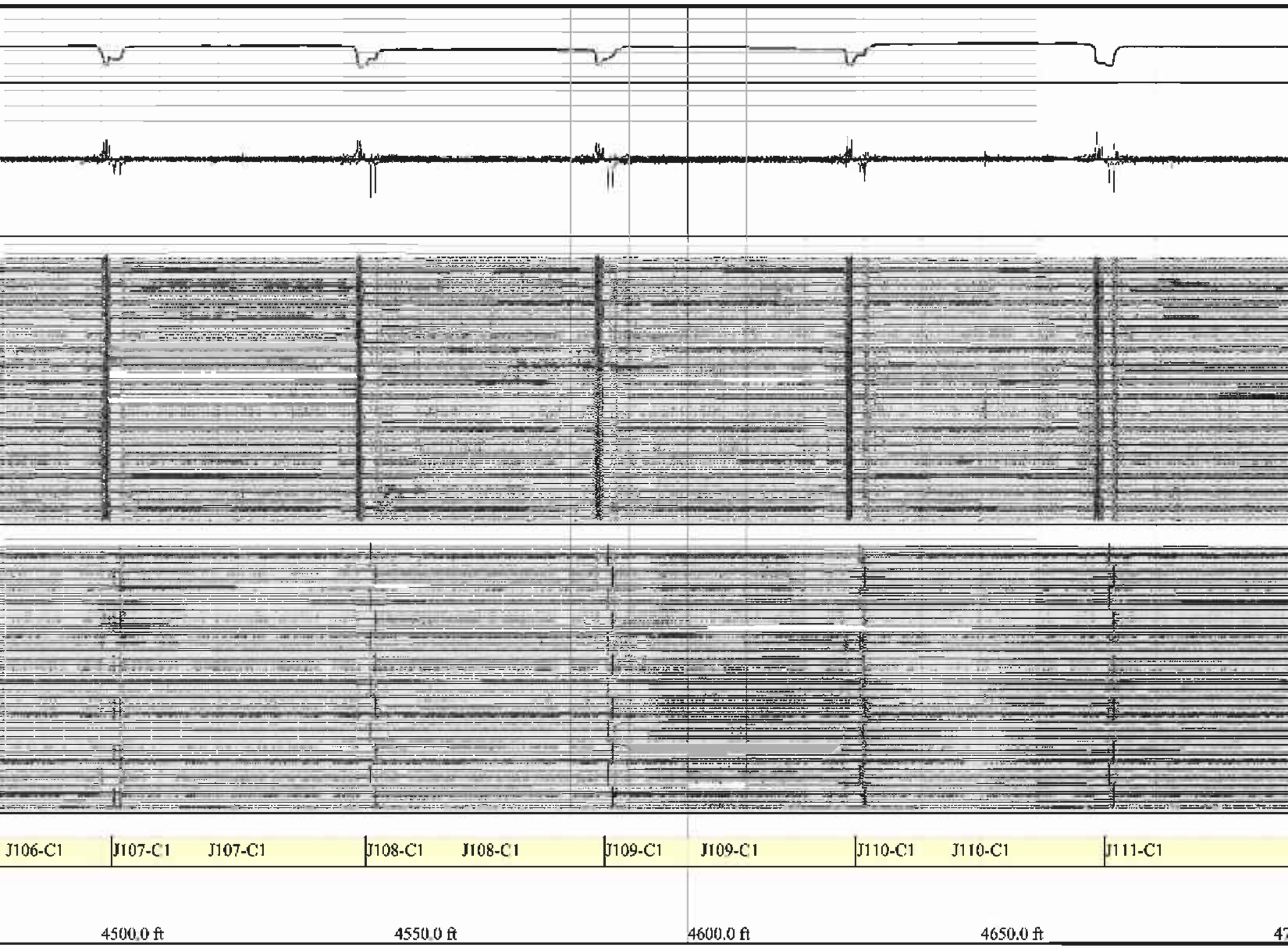
anomaly. FAIL
at 3355-3398'.

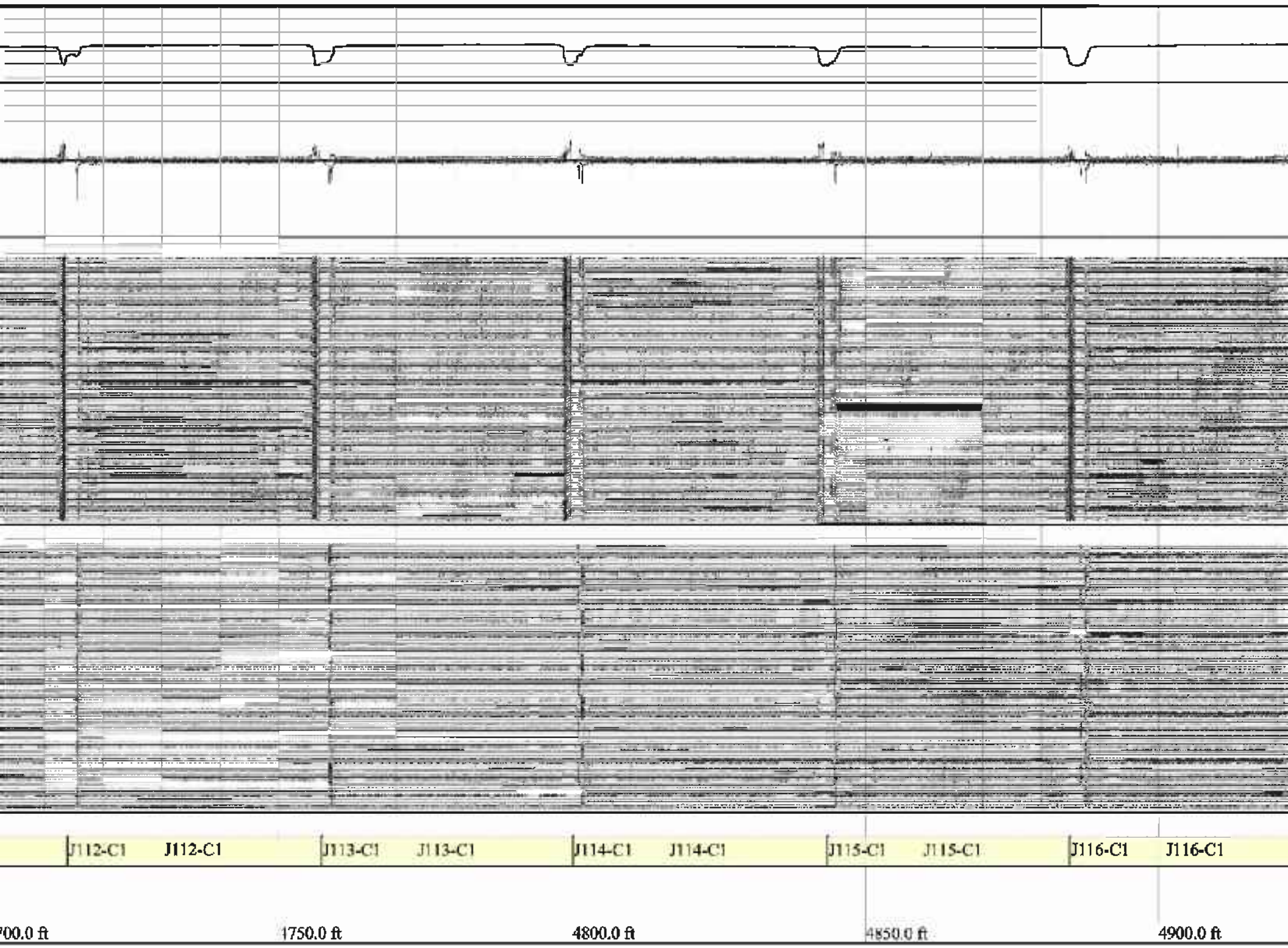

J86-C1
J86-C1
J87-C1
J87-C1
J88-C1
J88-C1
J89-C1
J89-C1
J90-C1
J90-C1
00.0 ft
3650.0 ft
3700.0 ft
3750.0 ft
3800.0 ft

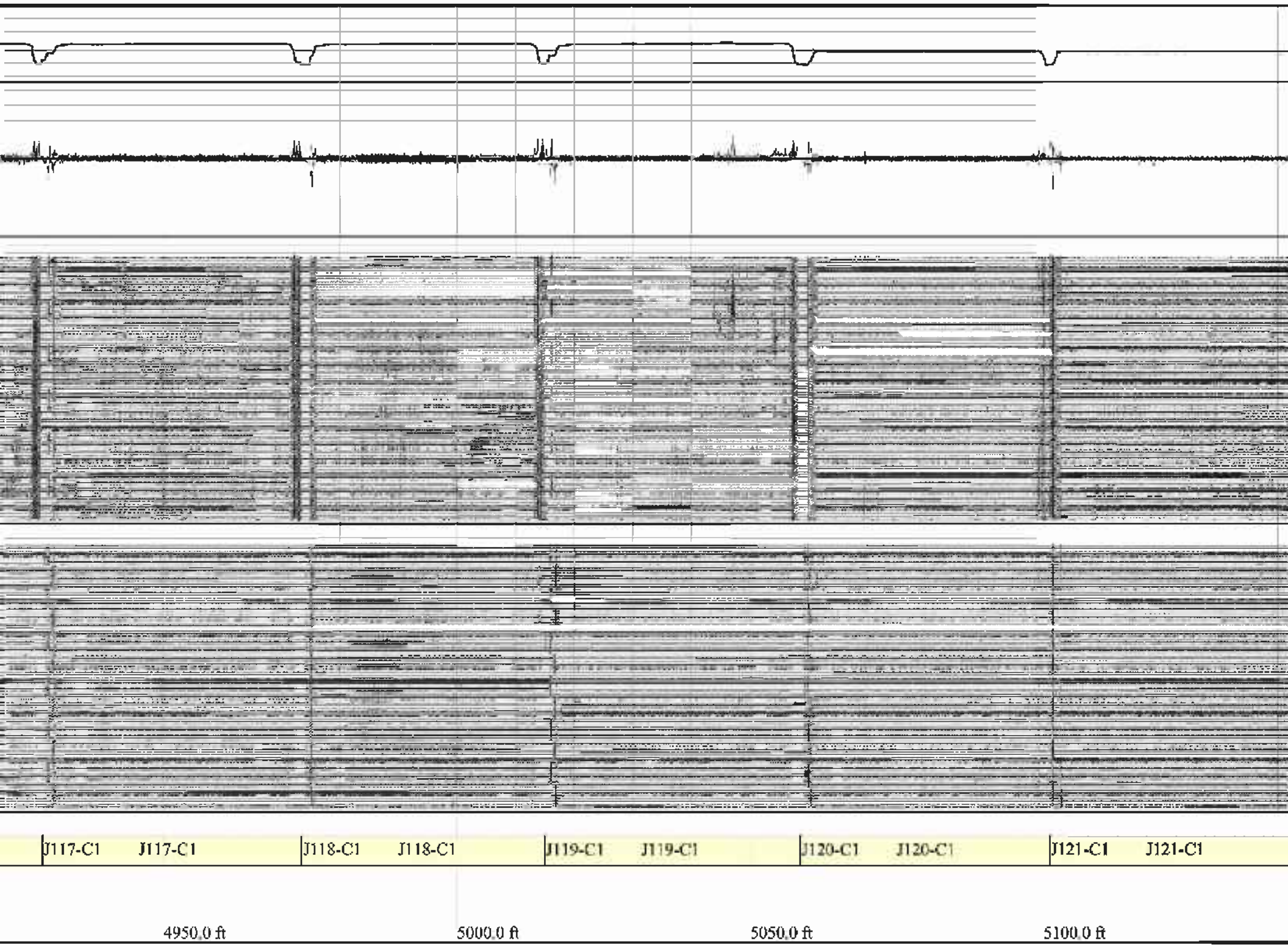

Clay Stick and Pull
Example. See Remarks
J91-C1
J91-C1
J92-C1
J92-C1
J93-C1
J93-C1
J94-C1
J94-C1
J95-C1
J95-C1
3850.0 ft
3900.0 ft
3950.0 ft
4000.0 ft

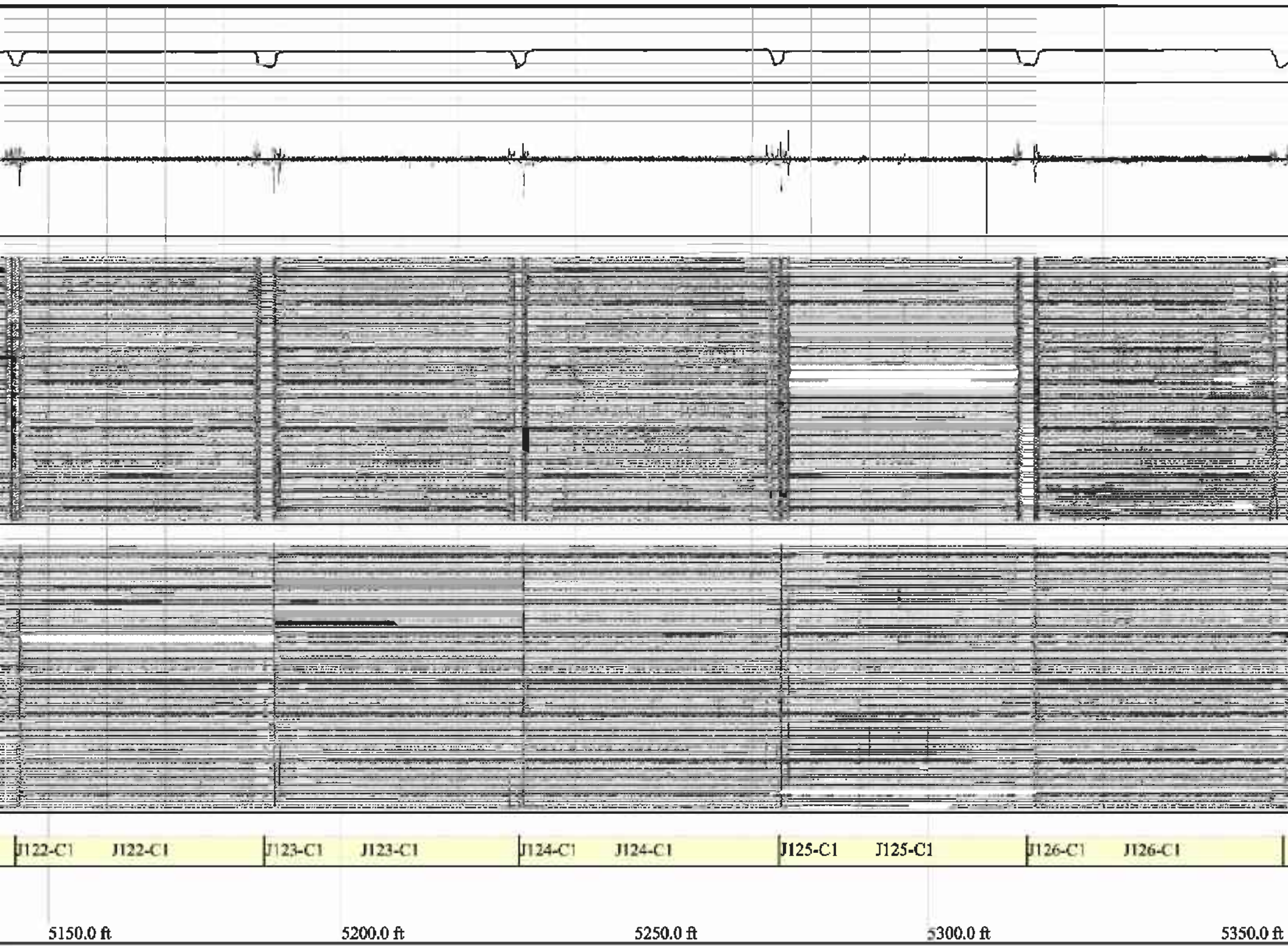

J96-C1
J96-C1
J97-C1
J97-C1
J98-C1
J98-C1
J99-C1
J99-C1
J100-C1
J100-C1
J101-C1
4050.0 ft
4100.0 ft
4150.0 ft
4200.0 ft
4250.0 ft

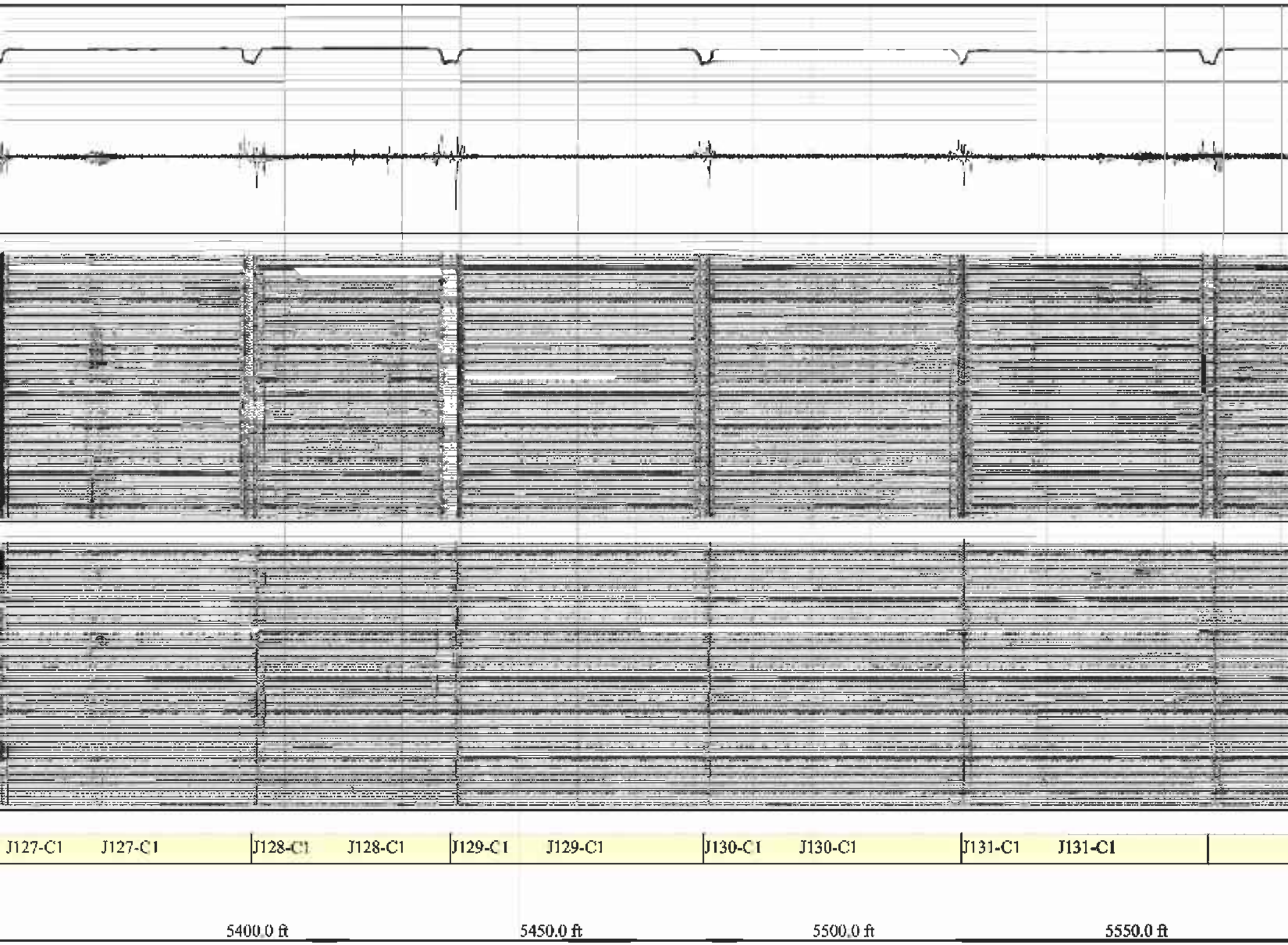

J101-C1
J102-C1
J102-C1
J103-C1
J103-C1
J104-C1
J104-C1
J105-C1
J105-C1
J106-C1
4300.0 ft
4350.0 ft
4400.0 ft
4450.0 ft

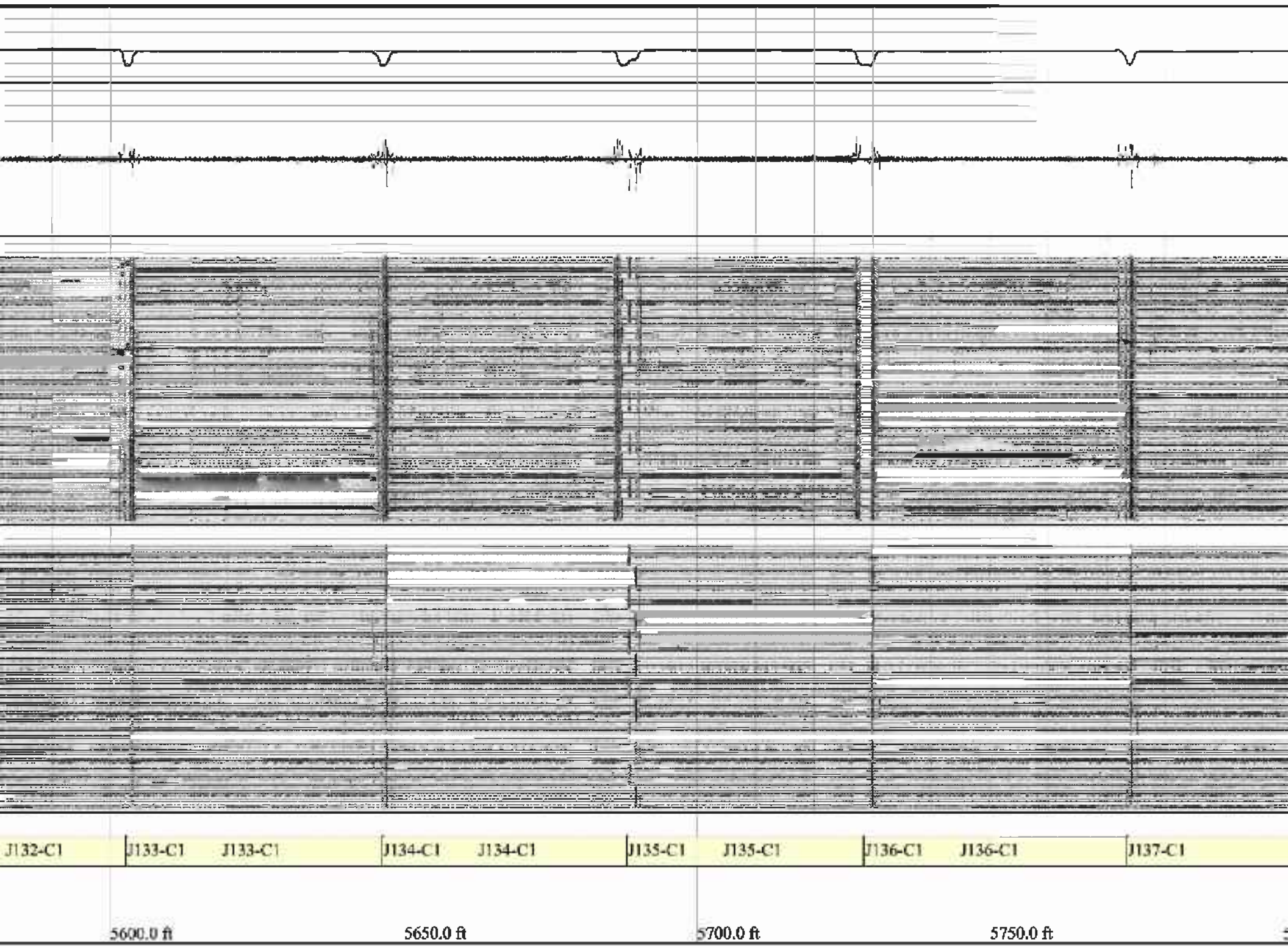

J106-C1
J107-C1
J107-C1
J108-C1
J108-C1
J109-C1
J109-C1
J110-C1
J110-C1
J111-C1
4500.0 ft
4550.0 ft
4600.0 ft
4650.0 ft

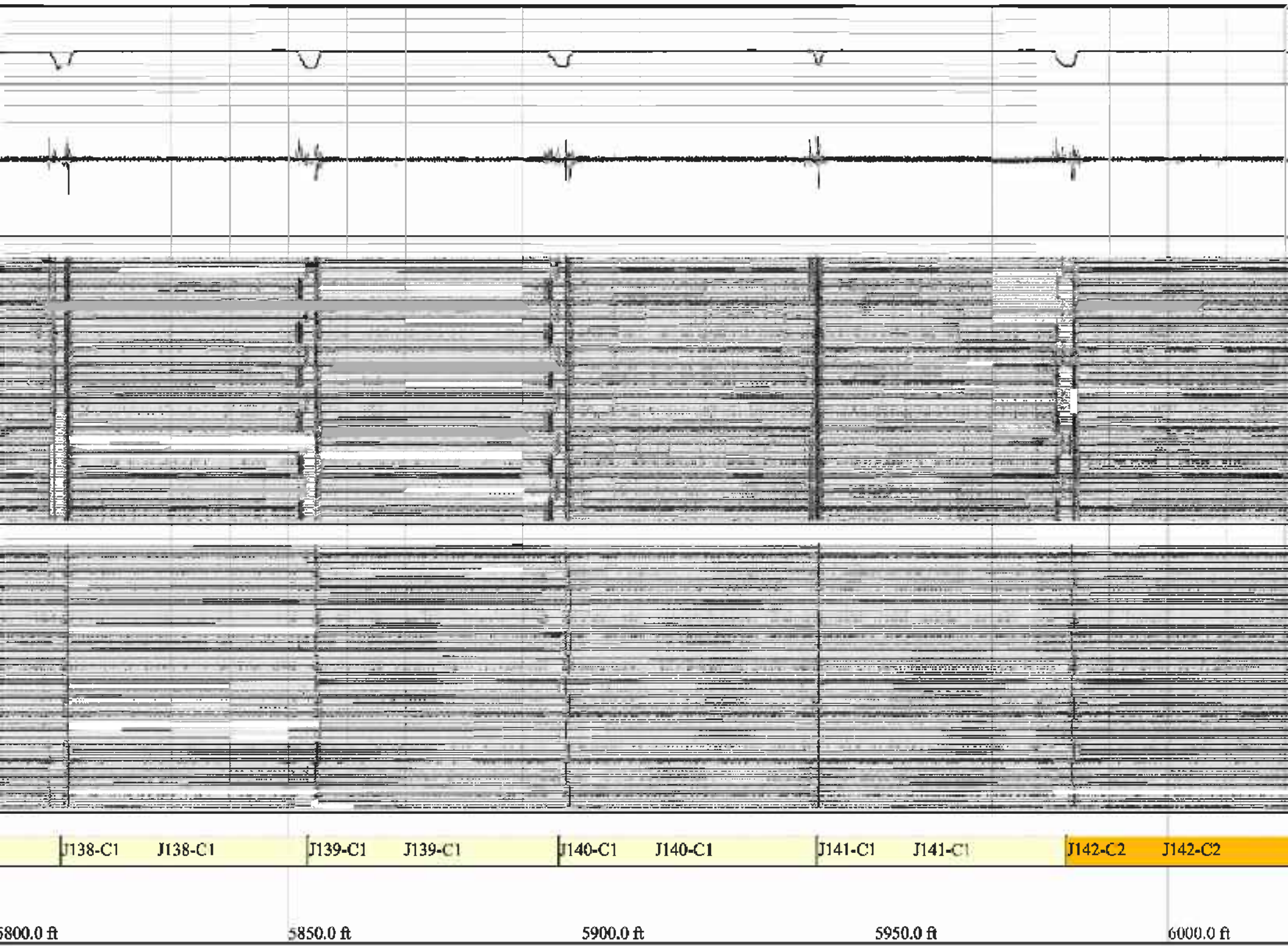

J112-C1
J112-C1
J113-C1
J113-C1
J114-C1
J114-C1
J115-C1
J115-C1
J116-C1
J116-C1
700.0 ft
1750.0 ft
4800.0 ft
4850.0 ft
4900.0 ft

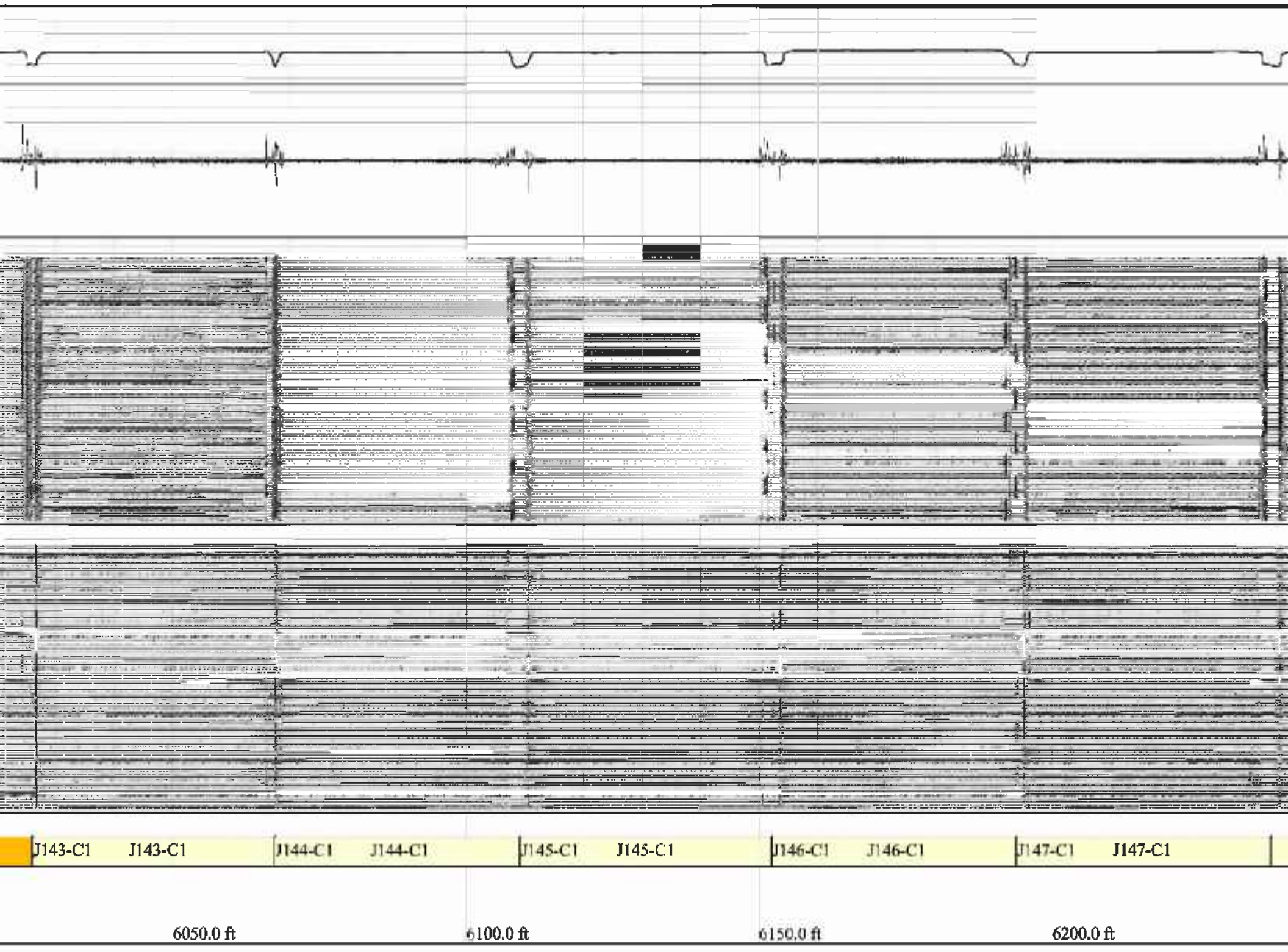

J117-C1
J117-C1
J118-C1
J118-C1
J119-C1
J119-C1
J120-C1
J120-C1
J121-C1
J121-C1
4950.0 ft
5000.0 ft
5050.0 ft
5100.0 ft

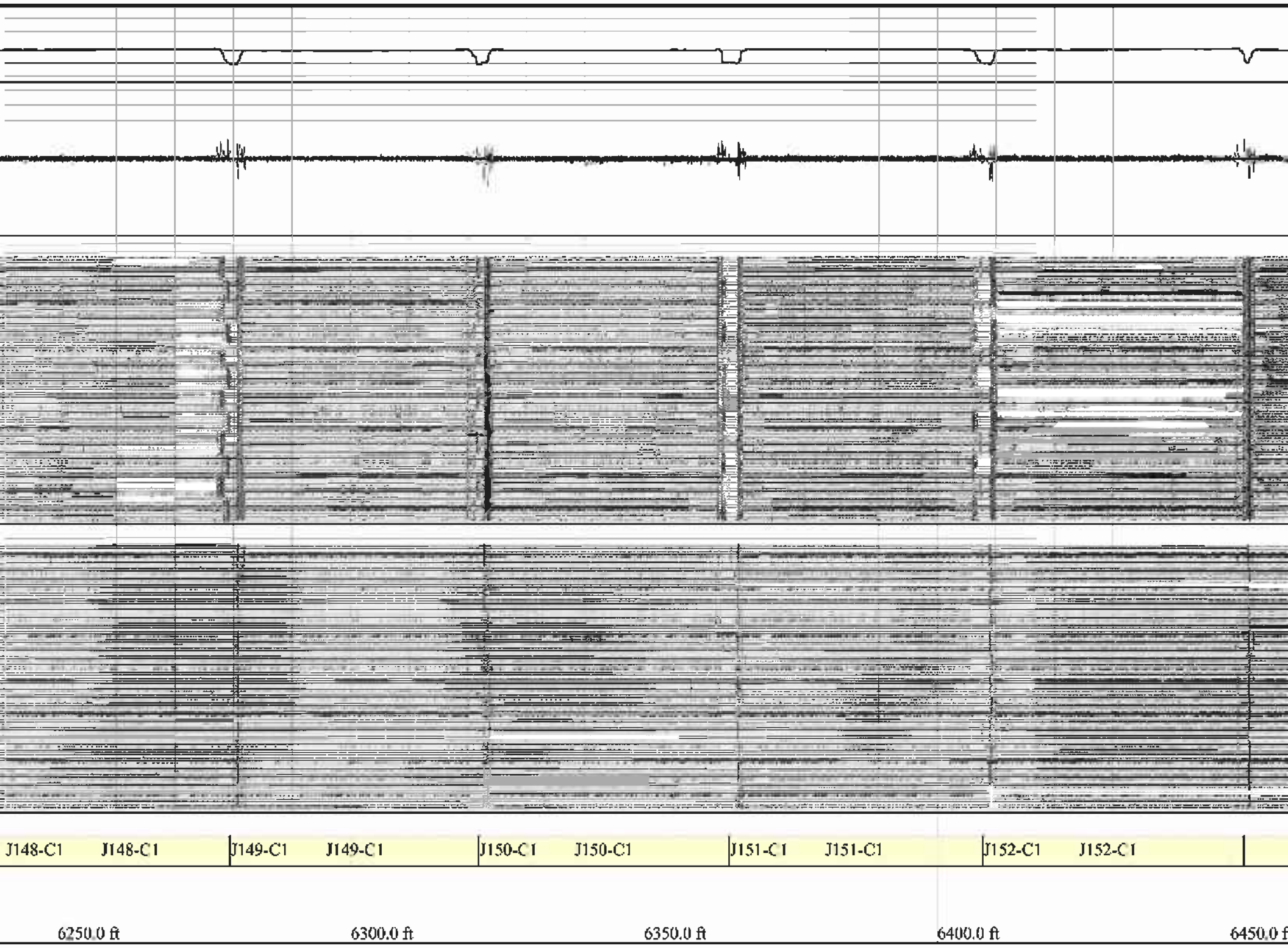

J122-C1
J122-C1
J123-C1
J123-C1
J124-C1
J124-C1
J125-C1
J125-C1
J126-C1
J126-C1
5150.0 ft
5200.0 ft
5250.0 ft
5300.0 ft
5350.0 ft


J127-C1
J127-C1
J128-C1
J128-C1
J129-C1
J129-C1
J130-C1
J130-C1
J131-C1
J131-C1
5400.0 ft
5450.0 ft
5500.0 ft
5550.0 ft


J132-C1
J133-C1
J133-C1
J134-C1
J134-C1
J135-C1
J135-C1
J136-C1
J136-C1
J137-C1
5600.0 ft
5650.0 ft
5700.0 ft
5750.0 ft


J138-C1
J138-C1
J139-C1
J139-C1
J140-C1
J140-C1
J141-C1
J141-C1
J142-C2
J142-C2
5800.0 ft
5850.0 ft
5900.0 ft
5950.0 ft
6000.0 ft


J143-C1
J143-C1
J144-C1
J144-C1
J145-C1
J145-C1
J146-C1
J146-C1
J147-C1
J147-C1
6050.0 ft
6100.0 ft
6150.0 ft
6200.0 ft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J150-C1
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J152-C1
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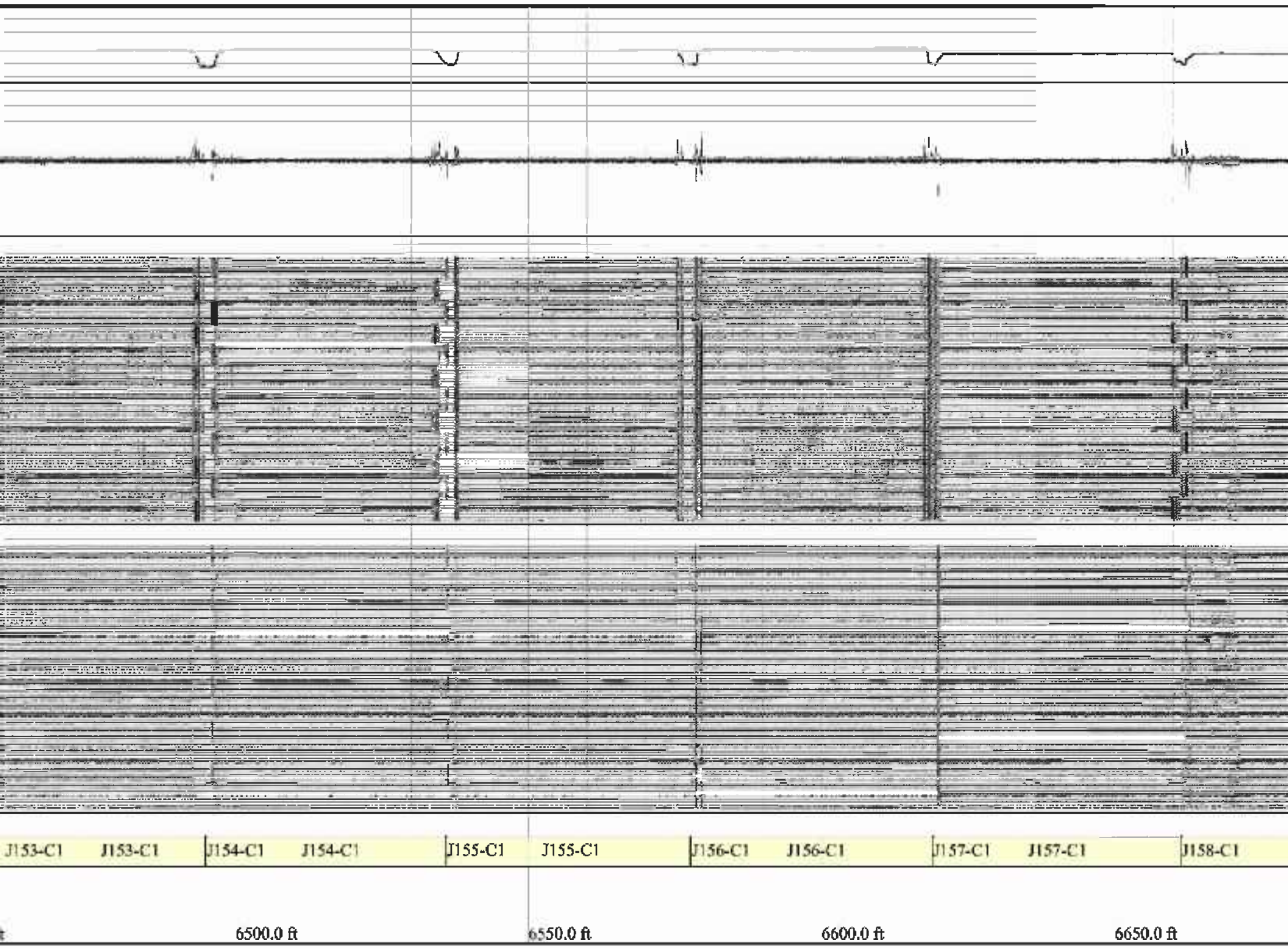
6450.0 f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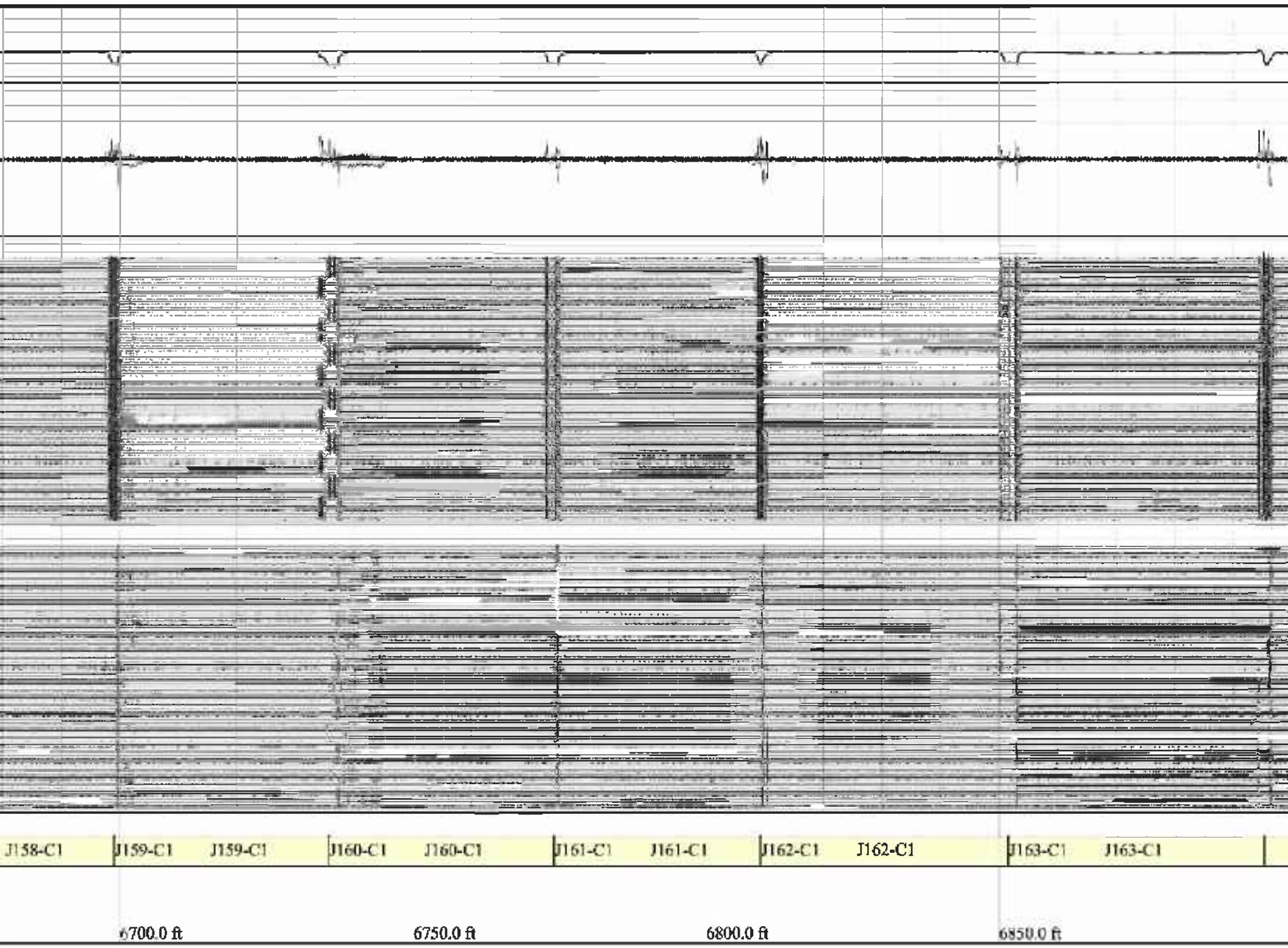
6550.0 ft
6600.0 ft
6650.0 ft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J161-C1
J161-C1
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J163-C1
J163-C1
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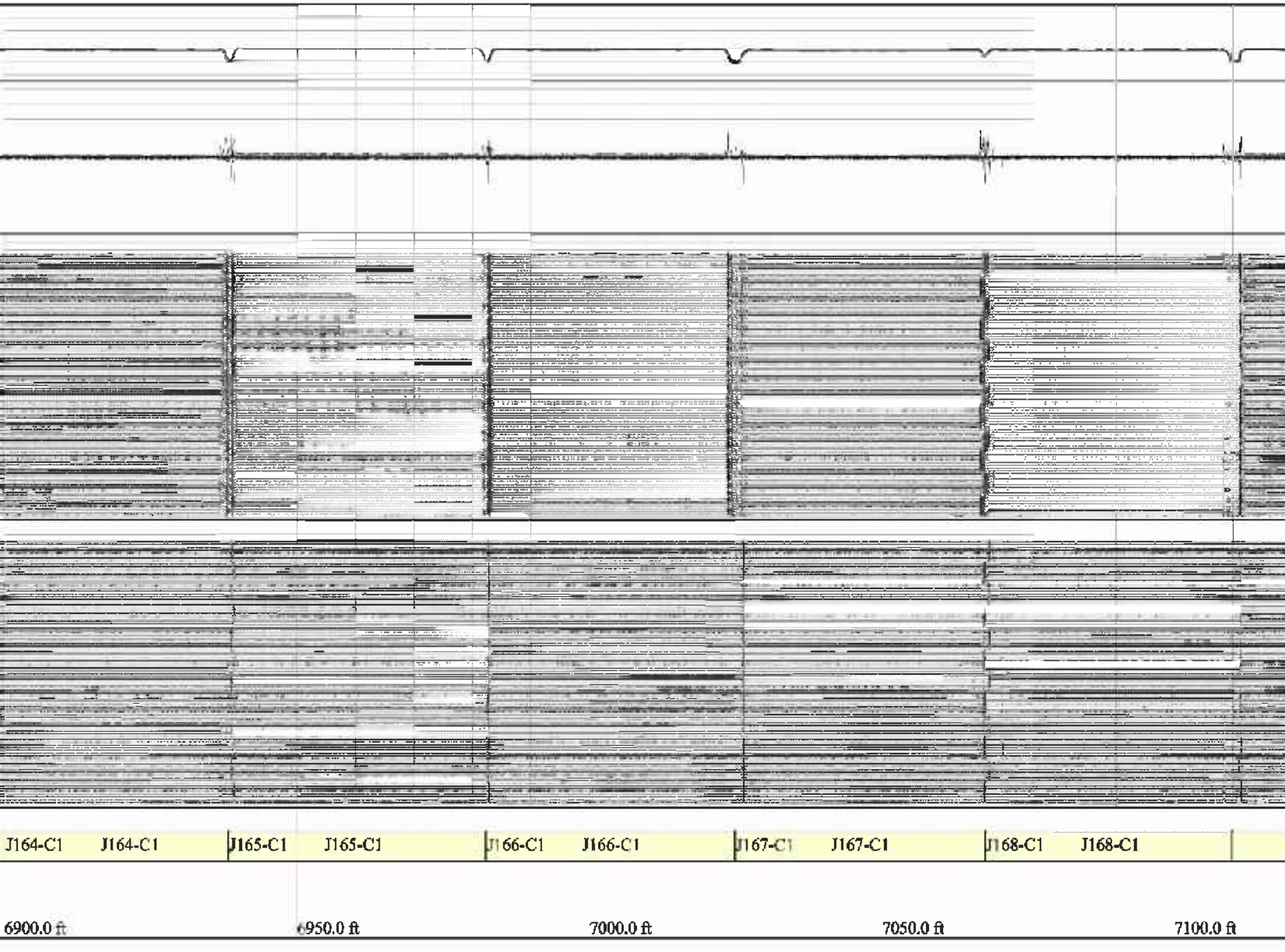
6800.0 ft
6850.0 ft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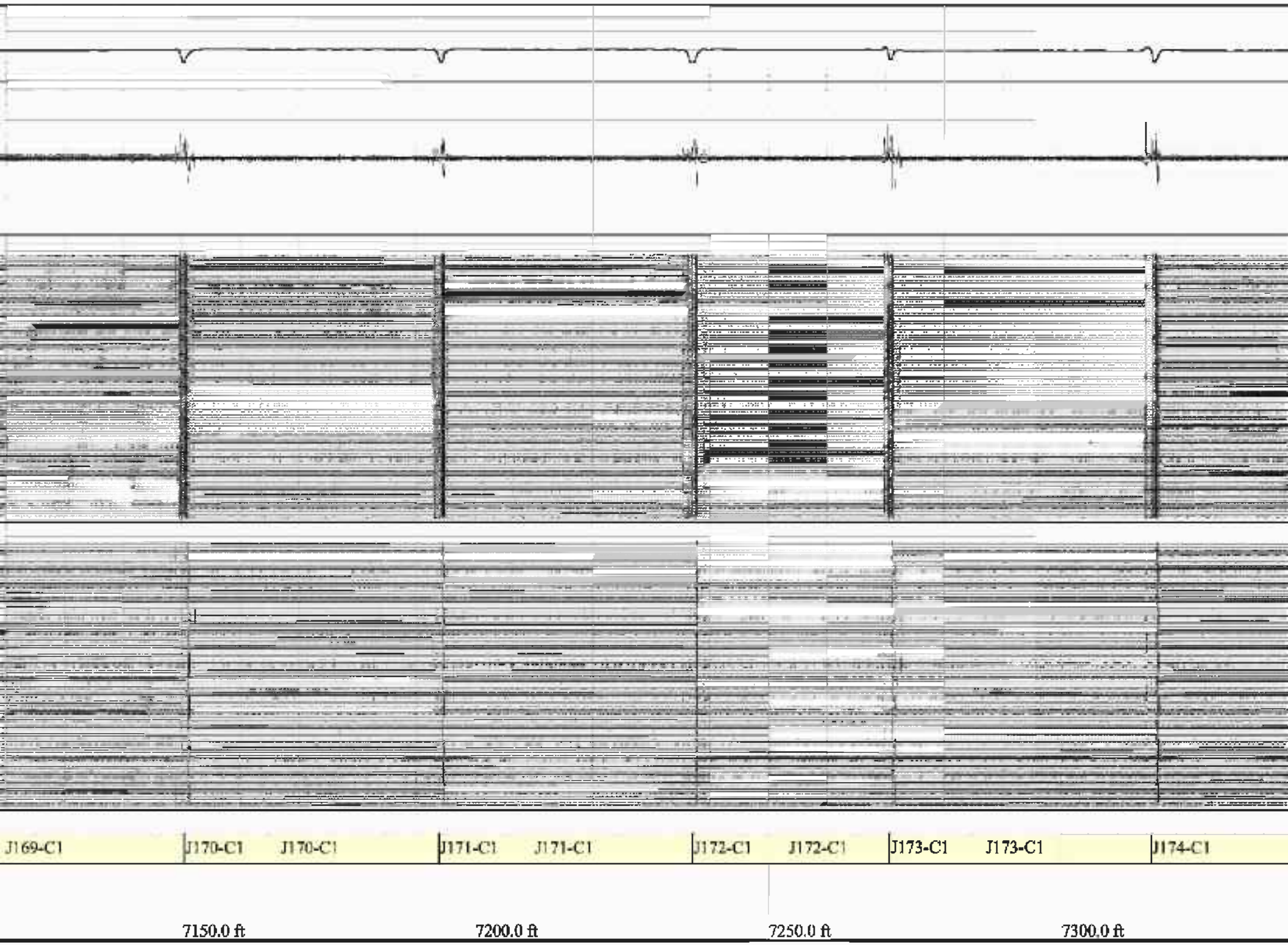
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J173-C1
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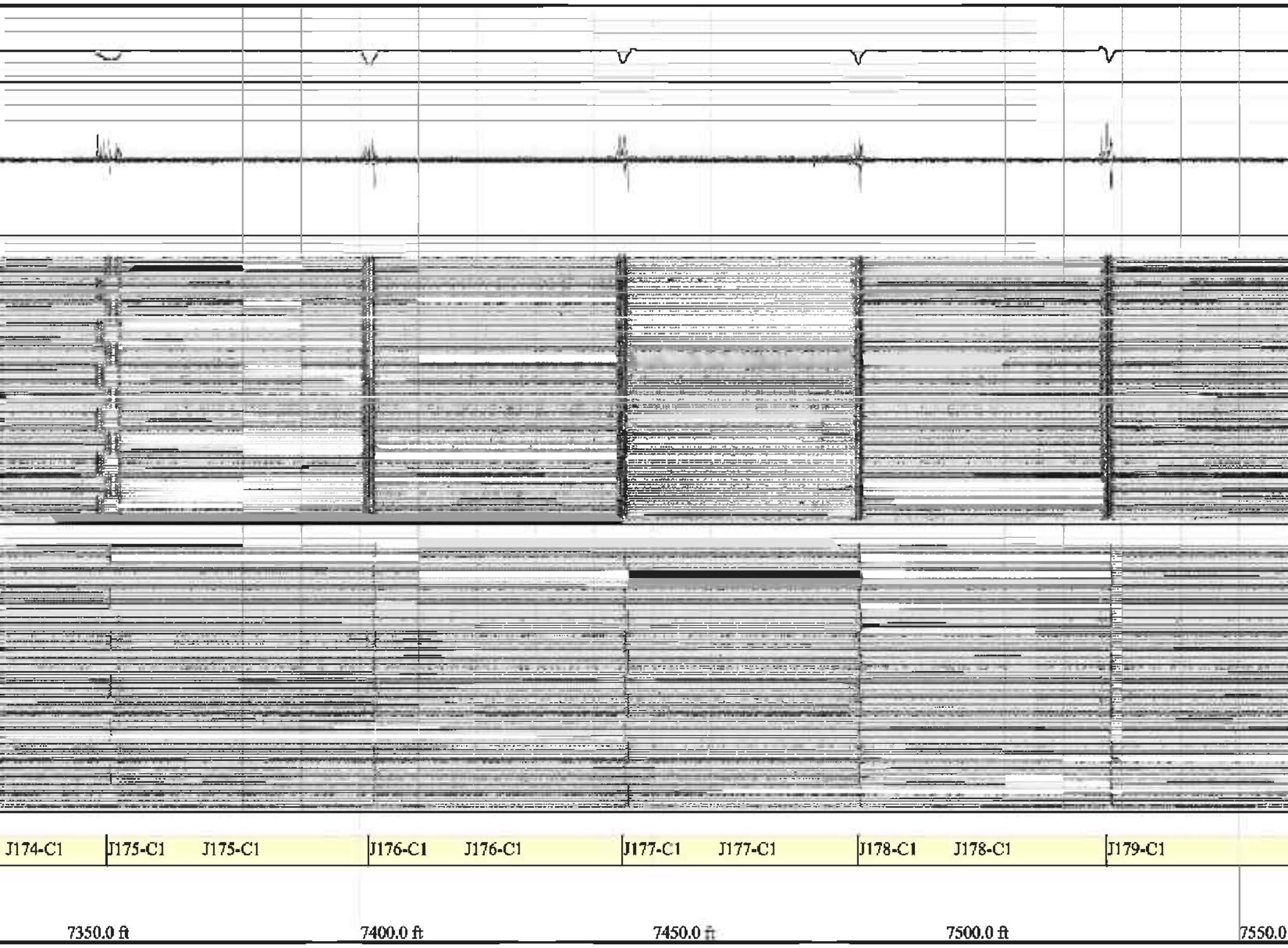
7300.0 ft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J177-C1
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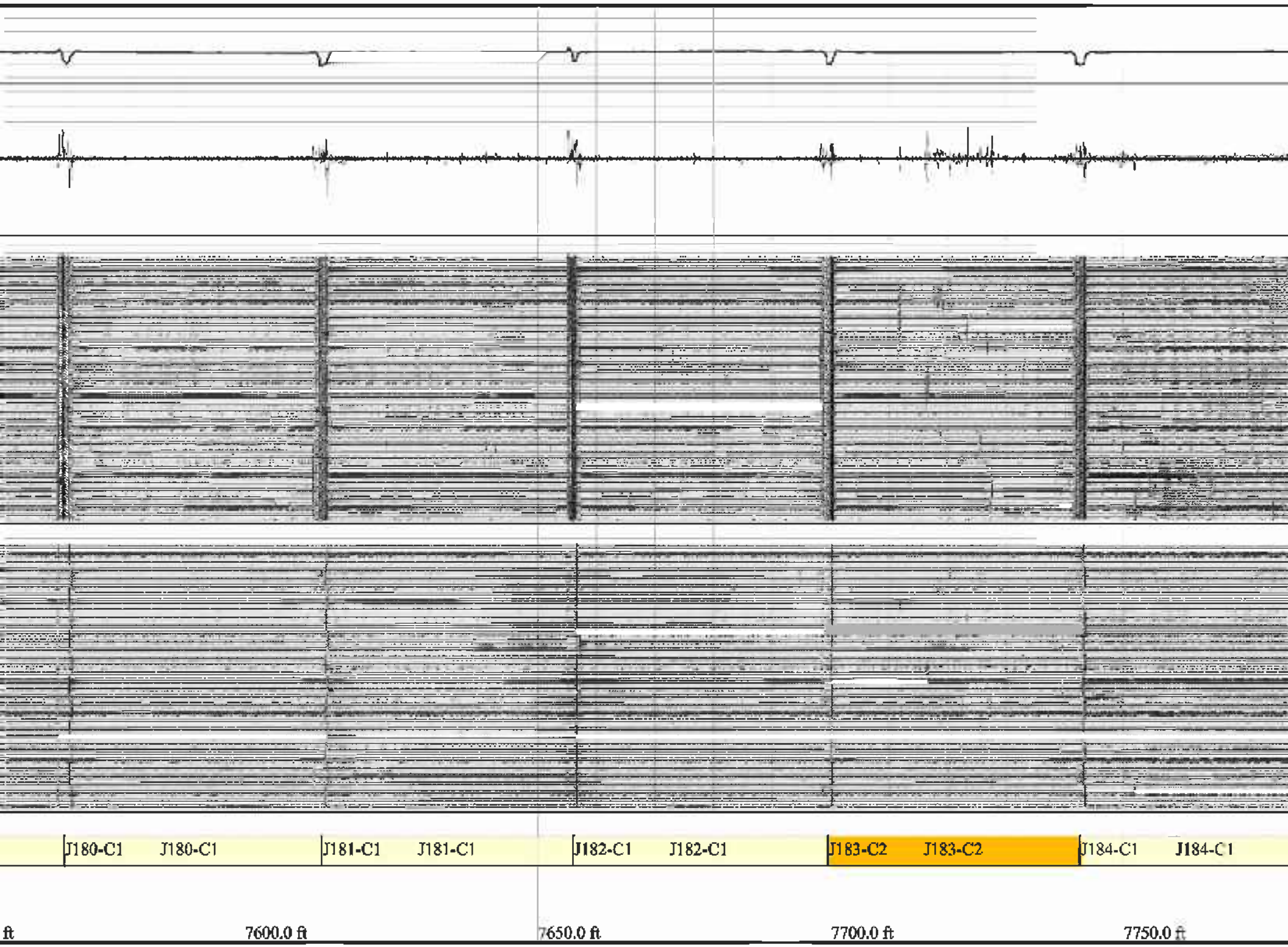
7550.0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J181-C1
J182-C1
J182-C1
J183-C2
J183-C2
J184-C1
J184-C1
ft
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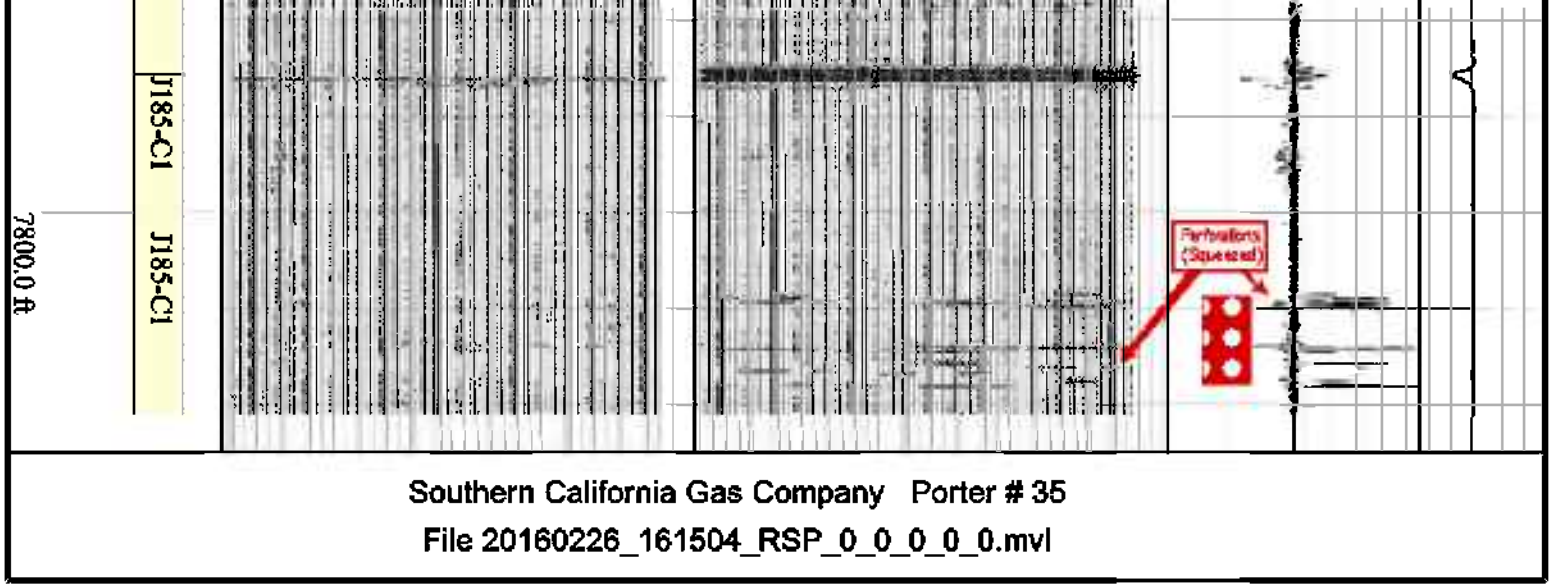
7750.0 ft



Joint Summary

Southern California Gas Company
Aliso Canyon Storage Pool
Porter # 35

Identifier	Start Log Depth	Joint Length	Diameter	Weight	Max ML Depth	Max ML Position	Min Burst Pressure	Joint Depth Class
	ft	ft	in	lb/ft	%	ft	psi	
JT-1	21.01	19.95	7.000	23.0	0			1
JT-2	40.96	40.91	7.000	23.0	0			1
JT-3	81.87	43.02	7.000	23.0	0			1
JT-4	124.90	43.11	7.000	23.0	0			1
JT-5	168.01	43.58	7.000	23.0	0			1
JT-6	211.59	43.11	7.000	23.0	0			1
JT-7	254.70	42.29	7.000	23.0	0			1
JT-8	296.99	43.39	7.000	23.0	0			1
JT-9	340.38	44.47	7.000	23.0	0			1
JT-10	384.84	42.57	7.000	23.0	0			1
JT-11	427.41	42.90	7.000	23.0	0			1
JT-12	470.31	43.43	7.000	23.0	0			1
JT-13	513.74	42.97	7.000	23.0	15	520.39	5746	1
JT-14	556.71	42.40	7.000	23.0	0			1
JT-15	599.11	41.38	7.000	23.0	0			1
JT-16	640.49	43.41	7.000	23.0	0			1
JT-17	683.90	43.77	7.000	23.0	0			1
JT-18	727.67	42.69	7.000	23.0	0			1
JT-19	770.36	43.53	7.000	23.0	0			1
JT-20	813.89	43.04	7.000	23.0	0			1
JT-21	856.93	43.49	7.000	23.0	0			1
JT-22	900.42	41.22	7.000	23.0	0			1
JT-23	941.64	41.30	7.000	23.0	18	975.28	5830	1
JT-24	982.94	43.79	7.000	23.0	0			1
JT-25	1026.73	43.54	7.000	23.0	0			1
JT-26	1070.27	42.90	7.000	23.0	0			1

JT-27	1113.17	41.50	7.000	23.0	0				1
JT-28	1154.67	43.54	7.000	23.0	0				1
JT-29	1198.20	44.25	7.000	23.0	0				1

Southern California Gas Company
Aliso Canyon Storage Pool
Porter # 35

Identifier	Start Log Depth	Joint Length	Diameter	Weight	Max ML Depth	Max ML Position	Min Burst Pressure	Joint Depth Class
	ft	ft	in	lb/ft	%	ft	psi	
JT-30	1242.45	43.14	7.000	23.0	0			1
JT-31	1285.60	42.68	7.000	23.0	0			1
JT-32	1328.28	42.02	7.000	23.0	0			1
JT-33	1370.30	42.14	7.000	23.0	0			1
JT-34	1412.43	43.04	7.000	23.0	0			1
JT-35	1455.48	42.47	7.000	23.0	0			1
JT-36	1497.95	41.22	7.000	23.0	0			1
JT-37	1539.17	41.77	7.000	23.0	0			1
JT-38	1580.93	42.33	7.000	23.0	0			1
JT-39	1623.27	42.49	7.000	23.0	0			1
JT-40	1665.75	43.34	7.000	23.0	0			1
JT-41	1709.09	41.74	7.000	23.0	0			1
JT-42	1750.83	41.37	7.000	23.0	0			1
JT-43	1792.20	43.25	7.000	23.0	0			1
JT-44	1835.45	43.39	7.000	23.0	0			1
JT-45	1878.84	42.70	7.000	23.0	0			1
JT-46	1921.53	41.91	7.000	23.0	0			1
JT-47	1963.44	42.30	7.000	23.0	0			1
JT-48	2005.74	42.35	7.000	23.0	0			1
JT-49	2048.09	41.88	7.000	23.0	19	2088.42	5371	1
JT-50	2089.96	42.20	7.000	23.0	20	2124.34	5815	2
JT-51	2132.17	42.70	7.000	23.0	32	2136.38	5286	2
JT-52	2174.87	40.53	7.000	23.0	0			1
JT-53	2215.40	42.45	7.000	23.0	17	2245.31	5779	1
JT-54	2257.84	42.57	7.000	23.0	0			1
JT-55	2300.41	42.71	7.000	23.0	0			1
JT-56	2343.13	42.15	7.000	23.0	0			1
JT-57	2385.28	42.15	7.000	23.0	0			1
JT-58	2427.43	43.07	7.000	23.0	0			1

Southern California Gas Company
Aliso Canyon Storage Pool
Porter # 35

Identifier	Start Log Depth	Joint Length	Diameter	Weight	Max ML Depth	Max ML Position	Min Burst Pressure	Joint Depth Class
	ft	ft	in	lb/ft	%	ft	psi	
JT-59	2470.50	42.48	7.000	23.0	0			1
JT-60	2512.97	41.96	7.000	23.0	0			1
JT-61	2554.93	43.45	7.000	23.0	0			1
JT-62	2598.39	42.04	7.000	23.0	0			1
JT-63	2640.42	38.72	7.000	23.0	16	2658.25	5744	1
JT-64	2679.14	42.77	7.000	23.0	0			1
JT-65	2721.91	42.18	7.000	23.0	0			1
JT-66	2764.09	42.97	7.000	23.0	0			1
JT-67	2807.06	41.95	7.000	23.0	21	2826.16	5720	2
JT-68	2849.01	43.26	7.000	23.0	0			1
JT-69	2892.27	43.15	7.000	23.0	0			1
JT-70	2935.42	42.01	7.000	23.0	0			1
JT-71	2977.43	42.89	7.000	23.0	22	2981.57	5758	2
JT-72	3020.33	42.21	7.000	23.0	0			1
JT-73	3062.54	42.37	7.000	23.0	0			1
JT-74	3104.90	42.83	7.000	23.0	15	3116.57	5784	1
JT-75	3147.74	41.98	7.000	23.0	16	3182.39	5704	1
JT-76	3189.72	41.95	7.000	23.0	0			1
JT-77	3231.67	39.65	7.000	23.0	0			1
JT-78	3271.32	42.36	7.000	23.0	0			1
JT-79	3313.68	42.11	7.000	23.0	0			1
JT-80	3355.79	42.34	7.000	23.0	85	3396.30	0	4
JT-81	3398.13	43.14	7.000	23.0	86	3420.03	0	4
JT-82	3441.27	42.86	7.000	23.0	61	3463.54	5360	4
JT-83	3484.13	42.59	7.000	23.0	0			1
JT-84	3526.71	41.09	7.000	23.0	0			1
JT-85	3567.80	43.11	7.000	23.0	0			1
JT-86	3610.91	40.81	7.000	23.0	0			1
JT-87	3651.72	40.81	7.000	23.0	0			1

anomaly.
FAIL at
3355-3398'

Inspection Date: 02-26-2016
Report Date: 03-01-2016

Joint Summary

Southern California Gas Company
Aliso Canyon Storage Pool
Porter # 35

Identifier	Start Log Depth	Joint Length	Diameter	Weight	Max ML Depth	Max ML Position	Min Burst Pressure	Joint Depth Class
	ft	ft	in	lb/ft	%	ft	psi	
JT-88	3692.53	42.30	7.000	23.0	0			1
JT-89	3734.82	42.96	7.000	23.0	0			1
JT-90	3777.78	42.36	7.000	23.0	0			1
JT-91	3820.15	42.31	7.000	23.0	0			1
JT-92	3862.45	43.56	7.000	23.0	0			1
JT-93	3906.01	43.53	7.000	23.0	0			1
JT-94	3949.54	43.92	7.000	23.0	0			1
JT-95	3993.45	40.76	7.000	23.0	0			1
JT-96	4034.21	42.66	7.000	23.0	0			1

JT-97	4076.87	42.34	7.000	23.0	0		1
JT-98	4119.21	43.81	7.000	23.0	0		1
JT-99	4163.02	41.59	7.000	23.0	0		1
JT-100	4204.61	42.52	7.000	23.0	0		1
JT-101	4247.13	41.93	7.000	23.0	0		1
JT-102	4289.06	42.85	7.000	23.0	0		1
JT-103	4331.91	43.32	7.000	23.0	0		1
JT-104	4375.23	39.56	7.000	23.0	0		1
JT-105	4414.79	43.53	7.000	23.0	0		1
JT-106	4458.32	43.59	7.000	23.0	0		1
JT-107	4501.90	43.24	7.000	23.0	0		1
JT-108	4545.14	40.72	7.000	23.0	0		1
JT-109	4585.85	42.89	7.000	23.0	0		1
JT-110	4628.75	42.45	7.000	23.0	0		1
JT-111	4671.20	42.93	7.000	23.0	0		1
JT-112	4714.13	43.22	7.000	23.0	0		1
JT-113	4757.35	42.90	7.000	23.0	0		1
JT-114	4800.25	43.38	7.000	23.0	0		1
JT-115	4843.64	41.40	7.000	23.0	0		1
JT-116	4885.03	44.36	7.000	23.0	0		1

Identifier	Start Log Depth	Joint Length	Diameter	Weight	Max ML Depth	Max ML Position	Min Burst Pressure	Joint Depth Class
	ft	ft	in	lb/ft	%	ft	psi	
JT-117	4929.40	44.29	7.000	23.0	0			1
JT-118	4973.68	41.44	7.000	23.0	0			1
JT-119	5015.12	43.64	7.000	23.0	15	5047.02	8063	1
JT-120	5058.76	42.47	7.000	26.0	0			1
JT-121	5101.23	43.27	7.000	26.0	0			1
JT-122	5144.50	42.54	7.000	26.0	0			1
JT-123	5187.05	43.33	7.000	26.0	0			1
JT-124	5230.38	44.35	7.000	26.0	0			1
JT-125	5274.73	42.30	7.000	26.0	0			1
JT-126	5317.03	43.71	7.000	26.0	16	5358.34	8967	1
JT-127	5360.74	43.69	7.000	26.0	0			1
JT-128	5404.43	33.91	7.000	26.0	0			1
JT-129	5438.33	43.17	7.000	26.0	0			1
JT-130	5481.50	44.06	7.000	26.0	0			1
JT-131	5525.55	42.04	7.000	26.0	0			1
JT-132	5567.60	35.17	7.000	26.0	0			1
JT-133	5602.76	43.69	7.000	26.0	0			1
JT-134	5646.45	41.72	7.000	26.0	0			1
JT-135	5688.17	40.46	7.000	26.0	0			1
JT-136	5728.63	44.84	7.000	26.0	0			1
JT-137	5773.47	37.83	7.000	26.0	15	5809.12	9149	1

JT-138	5811.29	42.08	7.000	26.0	0			1
JT-139	5853.37	42.85	7.000	26.0	0			1
JT-140	5896.22	44.06	7.000	26.0	0			1
JT-141	5940.29	42.44	7.000	26.0	0			1
JT-142	5982.72	43.44	7.000	26.0	21	6024.23	8808	2
JT-143	6026.16	41.25	7.000	26.0	0			1
JT-144	6067.41	41.86	7.000	26.0	0			1
JT-145	6109.27	42.93	7.000	26.0	16	6150.03	9141	1

Joint Summary

Southern California Gas Company
Aliso Canyon Storage Pool
Porter # 35

Identifier	Start Log Depth	Joint Length	Diameter	Weight	Max ML Depth	Max ML Position	Min Burst Pressure	Joint Depth Class
	ft	ft	in	lb/ft	%	ft	psi	
JT-146	6152.20	41.76	7.000	26.0	18	6191.30	9174	1
JT-147	6193.96	43.48	7.000	26.0	0			1
JT-148	6237.44	42.00	7.000	26.0	0			1
JT-149	6279.45	42.46	7.000	26.0	0			1
JT-150	6321.90	42.69	7.000	26.0	0			1
JT-151	6364.59	43.32	7.000	26.0	0			1
JT-152	6407.91	44.50	7.000	26.0	0			1
JT-153	6452.41	42.66	7.000	26.0	0			1
JT-154	6495.07	40.95	7.000	26.0	0			1
JT-155	6536.03	41.79	7.000	26.0	0			1
JT-156	6577.82	41.17	7.000	26.0	0			1
JT-157	6618.99	42.42	7.000	29.0	0			1
JT-158	6661.42	37.74	7.000	29.0	0			1
JT-159	6699.15	36.54	7.000	29.0	0			1
JT-160	6735.69	38.43	7.000	29.0	0			1
JT-161	6774.12	35.27	7.000	29.0	0			1
JT-162	6809.39	42.26	7.000	29.0	0			1
JT-163	6851.66	43.70	7.000	29.0	0			1
JT-164	6895.35	43.03	7.000	29.0	0			1
JT-165	6938.38	44.04	7.000	29.0	0			1
JT-166	6982.42	42.57	7.000	29.0	0			1
JT-167	7024.99	42.74	7.000	29.0	0			1
JT-168	7067.73	42.28	7.000	29.0	0			1
JT-169	7110.01	40.55	7.000	29.0	0			1
JT-170	7150.56	43.34	7.000	29.0	0			1
JT-171	7193.90	43.29	7.000	29.0	0			1
JT-172	7237.19	33.56	7.000	29.0	0			1
JT-173	7270.75	44.70	7.000	29.0	0			1
JT-174	7315.45	41.45	7.000	29.0	0			1

Southern California Gas Company
Aliso Canyon Storage Pool
Porter # 35

Identifier	Start Log Depth	Joint Length	Diameter	Weight	Max ML Depth	Max ML Position	Min Burst Pressure	Joint Depth Class
	ft	ft	in	lb/ft	%	ft	psi	
JT-175	7356.90	44.63	7.000	29.0	0			1
JT-176	7401.53	43.35	7.000	29.0	0			1
JT-177	7444.88	40.15	7.000	29.0	0			1
JT-178	7485.03	42.38	7.000	29.0	0			1
JT-179	7527.41	41.92	7.000	29.0	0			1
JT-180	7569.33	43.94	7.000	29.0	0			1
JT-181	7613.27	42.93	7.000	29.0	0			1
JT-182	7656.20	43.40	7.000	29.0	0			1
JT-183	7699.61	42.96	7.000	29.0	27	7727.40	10031	2
JT-184	7742.57	43.18	7.000	29.0	0			1
JT-185	7785.74	35.40	7.000	29.0	19	7787.06	10349	1

Ex. I – 49

Due to the large file size, this exhibit is an excerpt. The native file of this document is available upon request.

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION
DIVISION OF OIL, GAS, AND GEOTHERMAL RESOURCES

Rec'd 10-13-16 DOGGR Ventura.

HISTORY OF OIL OR GAS WELL

Operator Southern California Gas Company Field Aliso Canyon County

Well Porter 35 Sec. 28, T3N, R16W, S.B.B.&M.

A.P.I. No. 03700722 Name Tom McMahon (Person submitting report) Title SIMP Project Manager (President, Secretary, or Agent)

Date 9/27/2016 (Month, day, year)

Signature Thomas J McMahon

Address PO Box 2300, SC9365, Chatsworth, CA, 91313-2300 Telephone Number 714-398-5020

History must be complete in all detail. Use this form to report all operations during drilling and testing of the well or during redrilling or altering the casing, plugging, or abandonment, with the dates thereof. Include such items as hole size, formation test details, amounts of cement used, top and bottom of plugs, perforation details, sidetracked junk, bailing tests, and initial production data.

Daily Operation Period: 1/4/2016 - 1/5/2016

Operations this Report Period (DOGGR)

Daily Operation Period: 1/5/2016 - 1/6/2016

Operations this Report Period (DOGGR)

Daily Operation Period: 1/6/2016 - 1/7/2016

Operations this Report Period (DOGGR)

Daily Operation Period: 1/7/2016 - 1/8/2016

Operations this Report Period (DOGGR)

Daily Operation Period: 1/8/2016 - 1/9/2016

Operations this Report Period (DOGGR)

Complete JSP & JSA, Hold safety meeting with rig personnel and WSM. Service rig equipment and start it. Check well pressures: SITP - 1460 psi & SICP - 200 psi. Field pressure - 1514 psi. Hold Pre-job safety meeting with Weatherford testers and R/U BOP testing equipment. BOP equipment was inspected by DOGGR personnel. Pressure test BOPE as per Gas Company Standard 224.05: Pressure test pipe and blind rams, all lines and connections at 300 psi low / 5000 psi high for 20 min. each test. Annular preventer at 300 psi low / 3500 psi high for 20 min each test. Good test. Bleed off pressure and R/D Weatherford equipment. Inspect all wellhead lock screws. All good. Secure well and hoist for the weekend.

Daily Operation Period: 1/11/2016 - 1/12/2016

Operations this Report Period (DOGGR)

CompleteJSP & JSA. Hold safety meeting with crew and WSM. Service and start rig equipment. Field pressure: 1364 psi. Check well pressure. SITP 1800 psi and SICP - 1700 psi. R/U kelly hose and return line. Pump 80 bbls of 3% KCL water down tubing. 0 psi & 60 bbls down the casing and attempted off pressure. Casing flowing. Pump 50 bbls of 3% KCL water down casing. 800 psi. Bleed off well to 0 psi. Pumped 50 bbls of 3% KCL water down casing. 0 psi. Monitor well for 30 minutes. Casing started flowing. Close well in as directed by WSM. Spot 500 bbls tank. Secure well and hoist till AM.

Daily Operation Period: 1/12/2016 - 1/13/2016

Operations this Report Period (DOGGR)

Complete JSP & JSA. Hold safety meeting with rig crew and WSM. Service rig and start. Field pressure - 1399 psi. Check well pressure. SITP - 1750 psi & SICP - 780 psi. Mix 738 bbl's of 8.5 ppg, 60 vis. polymer. and 90 bbl's of 8.5 ppg 80 vis polymer. Secure well and hoist till AM.

Daily Operation Period: 1/13/2016 - 1/14/2016

Operations this Report Period (DOGGR)

Held safety meeting. Service rig and equipment. Field pressure - 1385 psi, SITP - 1535 psi, SICP - 1200 psi. Rigged up kelly hose. Pumped 90 bbl's of 8.5 ppg, 80 vis polymer followed by 46 bbl's of 8.5 ppg 60 vis polymer began to bleed down casing. Continued to pump a total of 272 bbl's of 8.5 ppg 60 vis polymer. Gained circulation at 192 bbl's of polymer away. Circulate gas out of the well for 30 minutes. Checked well. Well dead. Monitor well for 30 minutes and backed out hanger rams. Opened well and attempted to pull seals from Baker packer. Working up to 80K and putting in right hand torque. Unable to pull seals. Held pre-job safety meeting with Ensign and Western Wireline. Spotted in and rigged up wireline unit and lubricator. Secure well and rig till AM.

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION
DIVISION OF OIL, GAS, AND GEOTHERMAL RESOURCES

Rec'd 10-13-16 DOGGR Ventura.

HISTORY OF OIL OR GAS WELL

Operator Southern California Gas Company Field Aliso Canyon County

Well Porter 35 Sec. 28, T3N, R16W, S.B.B.&M.

A.P.I. No. 03700722 Name Tom McMahon (Person submitting report) Title SIMP Project Manager (President, Secretary, or Agent)

Date 9/27/2016 (Month, day, year)

Signature

Address PO Box 2300, SC9365, Chatsworth, CA, 91313-2300 Telephone Number 714-398-5020

History must be complete in all detail. Use this form to report all operations during drilling and testing of the well or during redrilling or altering the casing, plugging, or abandonment, with the dates thereof. Include such items as hole size, formation test details, amounts of cement used, top and bottom of plugs, perforation details, sidetracked junk, bailing tests, and initial production data.

Daily Operation Period: 1/14/2016 - 1/15/2016

Operations this Report Period (DOGGR)

Held safety meeting. Service rig and equipment. Field pressure 1353 psi. Check well pressure: SITP - 0 psi. SICP 0 psi. Fill hole with 36 bbl's of 8.5 ppg 70 vis polymer. Open well. Held pre-job safety meeting with Western Wireline and crew. Rigged up lubricator. Run in with Radial Torch cutter and cut tubing at 7828'. Cutter stuck. Worked cutter free. Pulled out with cutter. Laid down lubricator. Work tubing up to 85K and using right hand torque. Rigged up kelly hose and circulated. No good. Shut down pump. Rigged up Lubricator and run in the Chemical cutter and cut tubing at 7774'. Pulled out with cutter and rigged down Western wireline. Filled hole with 10 bbl's of polymer. Pulled out of the hole standing back tubing. Filled the hole every 10 stands and tally tubing. Stood back 80 stands. Lost 100 bbl's of polymer for the day. Secure well.

Daily Operation Period: 1/15/2016 - 1/16/2016

Operations this Report Period (DOGGR)

Held safety meeting. Service rig and equipment. Field pressure - 1325 psi. Check well pressure: SITP - 0 psi, SICP - 0 psi. Open well. Filled well with 10 bbl's of 8.5 ppg 60 vis. polymer. Pulled out of the hole with (89) joints of 2 7/8" J-55 tubing. Break out and lay down (1) 2 7/8" J-55 pup jt, (1) gas mandrel (1) 2 7/8" pup jt and 17.38 of cut joint. Filling hole every 10 stands. Install 11" 5M x 7" 5M crossover flange and circulating head. Tally and pick up 5 3/4" washover shoe, 74.78' of 5 3/4" washover pipe. Drive sub and crossover with 2 7/8" N-80 pup joint. Run in hole with washpipe on (16) joints of 2 7/8" J-55 tubing. Found tight spot at 575'. Unable to work through. Pull out of the hole with washpipe and stand back. Change tubing equipment. Tally and pick up 7" all weight scraper. Run in hole on (250) joints of 2 7/8" J-55 tubing. Tagged top of fish at 7,768'. Pulled out of the hole and stood back (40) joints of 2 7/8" J-55 tubing. Filling the hole every 10 stands. At 15:25 had BOP drill with crew. 58 seconds to secure well. Discussed proper well control procedures. lost 188 bbl's of 8.5 ppg 60 vis polymer. Secure well for the weekend.

Daily Operation Period: 1/18/2016 - 1/19/2016

Operations this Report Period (DOGGR)

Held safety meeting. Service rig and equipment. Field pressure = 1211 psi. Check well pressure: SITP = 0 psi, SICP = 0 psi. Open well. Filled well with 1 bbl of 8.5 ppg 60 vis polymer. Pulled out of the hole. Stand back (260) joints of 2 7/8" J-55 tubing. Break out and lay down scraper. Make up 7" 23# positive scraper. Run in the hole and found a tight spot at 77'. Worked through. Run in hole with (22) joints of 2 7/8" J-55 tubing to 649'. Pulled out of the hole and stand back (22) joints of 2 7/8" J-55 tubing. Make up tandem scrapers. 7" 23# positive, 8' pup joint and 7" all weight scraper. Run in the hole on (18) joints of 2 7/8" and stopped at 567'. Pull out of the hole and stand back (18) joints of 2 7/8" J-55 tubing. Pick up 23' of 5 3/4" wash over pipe. Run in the hole on (26) joints of 2 7/8" J-55 tubing to 826'. Had light friction at 575'. Pull out of the hole and stand back (26) joints 2 7/8" J-55 tubing. Break out crossover and drive sub. Rig up handling equipment. Make up (2) joints of 5 3/4" washover pipe, drive sub and crossover. Rig down handling equipment. Run in the hole with 5 3/4" BHA on (246) joints of 2 7/8" J-55 tubing. Had to push through bad spot at 567'. Tail at 7,709'. Secure well and hoist till AM.

Daily Operation Period: 1/19/2016 - 1/20/2016

Operations this Report Period (DOGGR)

Held safety meeting. Service rig and equipment. Field pressure: 1175 psi. SITP = 0 psi, SICP = 0 psi. Open well. Filled hole. Hole was full. Rig up kelly stand. Reverse circulate. Broke circulation with 2.5 bbl's of 8.5 ppg 60 vis polymer at 2.5 bpm at 500 psi. Rotated tubing to get over fish at 7,768'. Washover fish to top of packer at 7,825'. Circulate for 30 minutes at 4 bpm at 800 psi. Pulled out of the hole and stood back (250) joints of 2 7/8" J-55 tubing. Filling the hole every 10 stands. Rig up 5 3/4" handling equipment. Broke out and laid down 5 3/4" washpipe and shoe. Rigged down handling equipment. Picked up and made up 5 3/4" overshot loaded with 2.875" grapple, 4 3/4" Bumper Sub, Tubing jar and 2 7/8" N-80 pup joint. Run in the hole on 2 7/8" J-55 tubing. Rigged up 2 7/8" Pancake swivel and engaged fish. Worked tubing from 50K to 70K. Pulled free. Pulled out of the hole. Laid down 2 joints of 2 7/8" N-80 tubing and stood back (198) joints of 2 7/8" J-55 tubing. Filling the hole every 10 stands. Secured well till AM.

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Operator Southern California Gas Company Field Aliso Canyon County

Well Porter 35 Sec. 28, T3N, R16W, S.B.B.&M.

A.P.I. No. 03700722 Name Tom McMahon (Person submitting report) Title SIMP Project Manager (President, Secretary, or Agent)

Date 9/27/2016 (Month, day, year)

Signature

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Daily Operation Period: 1/20/2016 - 1/21/2016

Operations this Report Period (DOGGR)

Ensign monthly safety meeting. Held safety meeting. Serviced rig and equipment. Field pressure: 1150 psi, SITP = 0 psi, SICP = 0 psi. Opened well and filled with 1 bbl of 8.5 ppg 60 vis polymer. Pulled out the hole with (50) joints of 2 7/8" J-55 tubing and BHA. Did not have fish. Broke out 5 3/4" overshot to add extension and change grapple. Made up bottom hole assembly as follows. 5 3/4" Overshot with 3 21/32" grapple, 13.98' of 5 3/4" extensions, Bumper sub, Tubing jar and (1) 2 7/8" N-80 pup joint. Ran in the hole with (248) joints of 2 7/8" J-55 tubing. Picked up (2) joints of 2 7/8" N-80 tubing and (1) 2 7/8" N-80 pup joint. Rotated tubing to get over top of fish at 7,768'. Engaged fish and jarred on fish 25K over. Rotated tubing with no success. Released from fish. Pulled out of the hole and stood back (50) joints of 2 7/8" J-55 tubing filling the hole every 10 stands. Secure well till the AM.

Daily Operation Period: 1/21/2016 - 1/22/2016

Operations this Report Period (DOGGR)

Held safety meeting, Service rig and equipment. Field pressure: 1125 psi, SITP = 0 psi, SICP = 0 psi. Filled well with 1 bbl of 8.5 ppg 60 vis polymer. Pulled out of the hole and stood back (198) joints of 2 7/8" J-55 tubing. Broke out and laid down fishing tools. Ran in the hole with (Weatherford) 7" 23-26# Bridge Plug and (251) joints of 2 7/8" J-55 tubing. Set Bridge Plug at 7,760' COE. Released from Bridge Plug and laid down 2 joints of 2 7/8" N-80 tubing. Filled casing and tested casing to 500 psi for 30 minutes. Good test and bled off pressure. Dump approximately 10' of sand. Displaced wit 44 bbl's of 8.5 ppg 60 vis polymer at 2 bpm. Pulled out of the hole and stood back (228) joints of 2 7/8" J -55 tubing. Filling the hole every 10 stands. Secure well till the AM.

Daily Operation Period: 1/22/2016 - 1/23/2016

Operations this Report Period (DOGGR)

Held safety meeting. Field pressure: 1091 psi, SITP = 0 psi, SICP = 0 psi. Open well and filled with 1 bbl of 8.5 ppg 60 vis polymer. Pulled out of the hole with (20) joints of 2 7/8" J-55 tubing and bridge plug running tool. Held BOP drill with rig personnel at 6:47 AM. 56 seconds to secure well and discussed proper well control procedures. Remove circulating head. Held pre-job safety meeting with WSM, Schlumberger and crew. Spotted in and rigged up wireline unit and equipment. Made up and ran in the hole with USIT log. Tag down at 7,754' (wireline measurement) and logged from 7,754' to surface. Kept well full while logging. Rigged down Schlumberger wireline unit. Ran in the hole with (20) joints of 2 7/8" J-55 tubing. Tubing tail at 621'. Did not loose any fluid this tour. Secured well for the weekend.

Daily Operation Period: 1/25/2016 - 1/26/2016

Operations this Report Period (DOGGR)

Held safety meeting. Field pressure = 1018 psi. SITP = 0 psi, SICP = 0 psi. Tried to fill well. Well was full. Pulled out of the hole with (20) joints of 2 7/8" J-55 tubing. Held pre-job safety meeting. Rigged up Scientific Drilling. Ran in hole with Gyro to 7,750'. Gyro well from 7,750' to surface. Rigged down Scientific Drilling. Prep well for Caliper log. Held pre-job safety meeting. Rigged up Western wireline unit. Ran in hole with 60 arm caliper to 7,744' (wireline measurement). Logged from 7,744' to surface. Rigged down Western wireline. Ran in the hole with (20) joints of 2 7/8" J-55 tubing. Secure well till the AM.

Daily Operation Period: 1/26/2016 - 1/27/2016

Operations this Report Period (DOGGR)

Held safety meeting. Field pressure = 1005 psi. SITP = 0 psi, SICP = 0 psi. Well standing full. Pulled out of the hole with (20) joints of 2 7/8" J-55 tubing. Made (WTFD) 7" test packer. Ran in the hole with (108) joints of 2 7/8" J-55 tubing. Set packer at 3,351'. Test casing below packer from sand plug at 7,754' to 3,351' to 1,920 psi for 30 minutes charted. Good test. Bled off well. Tested annulus from 3,351' to surface to 2,210 psi for 30 minutes charted. Bled off well and released packer. Pulled out of the hole with (22) joints of 2 7/8" J-55 tubing. Try to set packer at 2,700'. Could not set. Moved packer up to 2,681' and set. Tested annulus from 2,681' to surface to 2,500 psi for 30 minutes charted. Good test Bled off well and released packer. Pulled out of the hole with (24) joints of 2 7/.8" J-55 tubing. Set packer at 2,040'. Tested annulus from 2,040' to surface to 2,790 psi for 30 minutes charted. Good test. Bled off well and released packer. Pulled out of the hole with (22) joints of 2 7/8" J-55 tubing. Set packer at 1,390'. Tested annulus from 1,390' to surface to 3,080 psi for 30 minutes charted. Good test. Bled off well and released packer. Pulled (24) joints of 2 7/8" J-55 tubing. Set packer at 730'. Tested annulus from 730' to surface to 3,370 psi for 30 minutes charted. Good test. Bled off well and released packer. Pulled out of the hole with (22) joints of 2 7/8" J-55 tubing. Set packer at 70'. Tested annulus from 70' to surface to 3,400 psi for 30 minutes charted. Good test. Bled off well and released packer. Pulled out of the hole with (2) joints of 2 7/8" J-55 tubing and laid down packer. Filled well and shut blind rams. Tested casing from 7,754' to surface to 1,000 psi for 30 minutes charted. Witnessed by Kris Gustfson of the DOGGR. Bled off well and ran in the hole with (20) joints of 2 7/8" J-55 tubing. Secure well till the AM.

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Daily Operation Period: 1/27/2016 - 1/28/2016

Operations this Report Period (DOGGR)

Held safety meeting. Field pressure = 988 psi, SITP = 0 psi, SICP = 0 psi. Well standing full. Pulled out of the hole with (20) joints of 2 7/8" J-55 tubing. Nippled up shooting flange. Held pre-job safety meeting. Rigged up (Halliburton) wireline unit and lubricator. Ran in the Cast - M casing inspection log. Log from 7,753' to surface. Rigged down (Halliburton) wireline unit and lubricator. Nippled down shooting flange. Ran in the hole with (20) joints of 2 7/8" J-55 tubing. Secure well till the AM.

Daily Operation Period: 1/28/2016 - 1/29/2016

Operations this Report Period (DOGGR)

Held safety meeting. Field pressure 981 psi, SITP = 0 psi, SICP = 0 psi. Well standing full. Pulled out of the hole with (20) joints of 2 7/8" J-55 tubing and stood back. Rigged out hand rails and floor. Nippled down Annular preventer and double gate and riser spool. Nippled down 13 5/8" X 8" 5M tubing spool. Welder cut 5 bolts. Pulled 30K to remove tubing spool. Loaded out tubing spool and production tree to send to Cameron. Cameron inspected casing stub and seals. Nippled up 13 5/8" spool, 13 5/8" X 9" DSA and riser. Nippled up double gate BOP. Filled the hole and shut well in. Secure well till Monday.

Daily Operation Period: 2/1/2016 - 2/2/2016

Operations this Report Period (DOGGR)

Held safety meeting. Field pressure = 982 psi. SITP = 0 psi, SICP = 0 psi. Nippled down double gate BOP and riser. Nippled down crossover spool. Nippled up tubing spool and casing valve. Tested casing valve to 300 psi low and 5000 psi high for 30 minutes. No good. Worked valve. Retest. No good. Found leaking by VR plug. Pulled VR plug. Inspected plug and reset VR plug. Retested. Good test. Pulled VR plug.Packed void with plastic packing. Tested P seals to 300 psi low and 2600 psi high for 30 minutes. Good test. Tested void to 300 psi low and 2600 psi high for 30 minutes. Good test. Nippled up flange to casing valve. Nippled up riser. Nippled up double gate BOP and annular preventer. Secure well till the AM.

Daily Operation Period: 2/2/2016 - 2/3/2016

Operations this Report Period (DOGGR)

Held safety meeting. Field pressure = 982 psi. SITP = 0 psi. SICP = 0 psi. Continued nippling up choke line, kill line, hoses and function test BOP. Test connections to 1000 psi. Good test. Ran in well with (248) joints of 2 7/8" J-55 tubing. Rigged up to lay down tubing. Pulled out of the well laying down 2 7/8" J-55 tubing. Filled the well every 20 joints with 8.5 ppg 60 vis polymer. Laid down (228) joints. Left (20) joints of 2 7/8" J-55 tubing as a kill string. Secure well till the AM.

Daily Operation Period: 2/3/2016 - 2/4/2016

Operations this Report Period (DOGGR)

Held safety meeting. Service rig. Field pressure = 981 psi. SITP = 0 psi, SICP = 0 psi. Well standing full. Pulled out and laid down (20) joints of 2 7/8" J-55 tubing. (Doby Hagar) loaded out and hauled off (248) joints of 2 7/8" tubing and (1) cut joint. Offloaded (285) joints of 2 7/8", P-110 CTR tubing. Made up (Weatherford) retrieving tool. (Tuboscope) trained crew on handling the CTR tubing.Tallied and picked up (191) 2 7/8", P-110 CTR tubing. Secured well till the AM

Daily Operation Period: 2/4/2016 - 2/5/2016

Operations this Report Period (DOGGR)

Held safety meeting. Service rig. Field pressure = 978 psi. SITP = 0 psi, SICP = 0 psi. Continued Picking up 2 7/8", P-110 CTR tubing. Rigged up circulating rubber, tubing swivel and kelly hose to reverse circulate. Broke circulation at 3 bpm at 500 psi. Circulated out sand to bridge plug at 7,760'. Circulated clean with 80 bbl's of 8.5 ppg 60 vis. polymer. Shut down pump and release bridge plug. Rigged down circulating equipment. Pulled out of the well with 245 joints of 2 7/8", P-110 CTR tubing. Laid down bridge plug and retrieving tool. Tallied fishing tools and picked up 5 3/4' overshot with 2 7/8" grapple, (2) 5 3/4" extension, 5 3/4" X 3 1/2" IF drive sub. 4 3/4" lubricated bumper sub, 4 3/4" jar, (2) 4 3/4" drill collars, 4 3/4" slinger, 3 1/2" IF X 2 7/8" 8rd crossover. Could not make up bumper sub to drive sub. Bad thread. Change out bumper subs. Ran in the well with bottom hole assembly on (20) joints of 2 7/8", P-110 CTR tubing. Secure well till the AM.

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HISTORY OF OIL OR GAS WELL

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Daily Operation Period: 2/5/2016 - 2/6/2016

Operations this Report Period (DOGGR)

Held safety meeting. Service rig. Field pressure = 978 psi, SITP = 0 psi, SICP = 0 psi. Continued running in the well with (222) joints of 2 7/8", P-110 tubing and fishing BHA. Picked up (1) of 2 7/8", P-110 tubing and worked over fish. Set off jars at 40K over string weight twice and fish came free. Laid down (1) of 2 7/8", P-110 tubing and stood back (242) joints of 2 7/8", P-110 tubing. Broke down fishing tools and stood back drill collars. Laid down cut joint of 2 7/8", J-55 tubing, 4' - 2 7/8", J-55 pup joint, Camco KP-5 safety system, KP-5 safety nipple, Camco 20' blast joint, Camco NO GO "D" nipple and 2' of cut blast joint. Made up 5 3/4' overshot with 3 21/32" grapple, (1) 5 3/4" extension, 5 3/4" X 3 1/2" IF drive sub. 4 3/4" lubricated bumper sub, 4 3/4" jar, (2) 4 3/4" drill collars, 4 3/4" slinger, 3 1/2" IF X 2 7/8" 8rd crossover. Ran in the well with (100) joints of 2 7/8", P-110 tubing. Secure well for the weekend.

Daily Operation Period: 2/8/2016 - 2/9/2016

Operations this Report Period (DOGGR)

Held safety meeting. Service rig. Field pressure = 976 psi, SITP 0 psi, SICP = 0 psi. Well standing full. Open well. Continued running in the well with (140) joints of 2 7/8", P-110 tubing and fishing BHA. Picked up (5) joints of 2 7/8", P-110 tubing. Worked over top of fish. Pulled 30K over string weight to jar on fish. Grapple slipped off. Worked back over fish. Rotated while slowly pulling up to rotate seals out of the packer. We could get rotation down to the fish but would slip off when pulling up to setting off the jars. Dead pulled 70K over string weight and slip off of fish. Pulled out of the well with (244) joints of 2 7/8", P-110 tubing. Filled the well every 10 stands with 8.5ppg 60 vis polymer. Broke down fishing tools and stood back drill collars. Inspected grapple. Grapple was dull but could tell we were over the fish. Made up 5 3/4' overshot with 3 5/8" grapple, (1) 5 3/4" extension, 5 3/4" X 3 1/2" IF drive sub. 4 3/4" lubricated bumper sub, 4 3/4" jar, (2) 4 3/4" drill collars, 4 3/4" slinger, 3 1/2" IF X 2 7/8" 8rd crossover. Ran in the well with (204) joints of 2 7/8", P-110 tubing. Tail at 6,555'. Secure well till the AM.

Daily Operation Period: 2/9/2016 - 2/10/2016

Operations this Report Period (DOGGR)

Held safety meeting. Service rig. Field pressure = 961 psi. SITP = 0 psi, SICP = 0 psi. Open well. Continued running in with (41) joints of 2 7/8", P -110 CTR tubing. Rigged up circulating head. Circulated down to the fish at 3 bpm at 700 psi. Latched on to fish at 7,816'. Pressure spiked to 1,900 psi. Shutdown pump. Rigged down circulating equipment. Jarred on fish at 120K. Rotated to the right on fish while working tubing. Jarred on fish at 120K. Pulled free. Went back down to see if the grapple slipped off. Could not engage fish. Pulled out of the well with (245) joints of 2 7/8", P-110 CTR tubing. Filling the well every 10 stands with 8.5 ppg 68 vis polymer. Broke down fishing tools and stood back drill collars. Fish had parted at the latch. Recovered 8' of the cut blast joint and top of locator on top of the seal assembly. Installed dead line in rig. Ran in the well with (50) joints of 2 7/8", P-110 CTR tubing for a kill string. Lost 20 bbl's of 8.5 ppg 68 vis polymer this tour. Secure well till the AM.

Daily Operation Period: 2/10/2016 - 2/11/2016

Operations this Report Period (DOGGR)

Held safety meeting. Service rig. Field pressure = 934 psi, SITP = 0 psi, SICP = 0 psi. Open well. Filled well with 9 bbl's of 8.5 ppg 68 vis polymer. Pulled out of the well with (50) joints of 2 7/8", P-110 CTR tubing and stood back. Tallied and made up 6" X 5 3./4" mill shoe, 2' - 5 3/4" extension, 5 3/4" X 3 1/2" IF drive sub, 3 1/2" IF X 3 1/2" reg crossover, 5 7/8" boot basket, 3 1/2" reg X 3 1/2" IF sub, 4 3/4" jars, (4) 4 3/4" drill collars, 3 1/2" IF X 2 7/8" 8rd crossover, 2 7/8", 8rd X 2 7/8" CTR crossover. Ran on (243) joints of 2 7/8", P-110 CTR tubing. Tag top of packer at 7,824'. Rigged up circulating equipment and power swivel. Started milling at 2 1/2 bpm at 400 psi. Milled approximately 18". Circulated clean. Pulled high. Secure well till the AM.

Daily Operation Period: 2/11/2016 - 2/12/2016

Operations this Report Period (DOGGR)

Held safety meeting. Service rig. Field pressure = 890 psi. SITP = 0 psi, SICP = 0 psi. Open well. Well standing full. Continue milling over Baker Retieva D packer. Pumping at various rates and pumping both long and reverse circulating and dry milling. Made approximately 2 1/2 ft. We believe we are still in the element section. We could not make any more hole and had no torque. Possible parts are spinning or shoe is worn out. Decision was made to pull and inspect shoe. Reverse circulated clean with120 bbl's at 4 bpm at 800 psi. Rigged out power swivel. Laid down one joint of 2 7/8", P-110 CTR tubing. Pulled out of the well and stood back (190) joints of 2 7/8", P-110 CTR tubing. Filling the well every 10 stands with 8.5 ppg, 60 vis polymer. Secure well till the AM.

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Daily Operation Period: 2/12/2016 - 2/13/2016

Operations this Report Period (DOGGR)

Held safety meeting. Service rig, Field pressure = 910 psi, SITP = 0 psi, SICP = 0 psi. Open well. Filled well with 8.5 ppg 60 vis polymer. Pulled out of the hole with (50) joints of 2 7/8", P-110 CTR tubing. Filling the hole every 10 stands with 8.5 ppg 60 vis polymer. Broke down milling assembly. Stood back drill collars. Shoe was worn out. Made up new shoe. 6" X 5 3./4" mill shoe, 2' - 5 3/4" extension, 5 3/4" X 3 1/2" IF drive sub, 3 1/2" IF X 3 1/2" reg crossover, 5 7/8" boot basket, 3 1/2" reg X 3 1/2" IF sub, 4 3/4" jars, (4) 4 3/4" drill collars, 3 1/2" IF X 2 7/8" 8rd crossover, 2 7/8", 8rd X 2 7/8" CTR crossover. Ran in the hole with (245) joints of 2 7/8", P-110 CTR tubing. Rigged up power swivel. Continue milling on (Baker) 7" Retrieva D packer. Getting metal shavings and rubber back. Element rings are spinning. Working through the element section. Pulled high and reversed 2 tubing volumes. Lost 10 bbl's of 8.5 ppg 60 vis polymer this tour. Secure well till the AM.

Daily Operation Period: 2/13/2016 - 2/14/2016

Operations this Report Period (DOGGR)

Held safety meeting. Service rig. Field pressure = 926 psi. SITP = 0 psi, SICP = 0 psi. Opened well. Filled the hole with 1 bbl of 8.5 ppg 60 vis polymer. Continued milling operations. Reverse circulating at 1 bpm at 300 psi. Getting back good cuttings and some rubber pieces. Still looks as if we are fighting the rings spinning between the elements. Made a few inches. Continue milling. Stopped make hole and not very many cuttings. Circulated the hole clean at 4 bpm at 800 psi for 30 minutes. Rigged out power swivel. Pulled out of the hole with (192) joints of 2 7/8", P-100 CTR tubing. Filling the hole every 10 stands with 8.5 ppg 60 vis polymer. Held BOP drill, 58 seconds. Secure well till Monday.

Daily Operation Period: 2/15/2016 - 2/16/2016

Operations this Report Period (DOGGR)

Held safety meeting. Service rig. Field pressure = 948 psi, SITP = 0 psi, SICP = 0 psi. Open well. Filled hole with 8 bbl's of 8.5 ppg, 60 vis polymer. Continued pulling out with (50) joints of 2 7/8", P-110 CTR tubing and milling BHA. Broke down milling assembly and stood back drill collars. Made up new shoe. 6" X 5 3./4" mill shoe, 2' - 5 3/4" extension, 5 3/4" X 3 1/2" IF drive sub, 3 1/2" IF X 3 1/2" reg crossover, 5 7/8" boot basket, 3 1/2" reg X 3 1/2" IF sub, 4 3/4" jars, (4) 4 3/4" drill collars, 3 1/2" IF X 2 7/8" 8rd crossover, 2 7/8", 8rd X 2 7/8" CTR crossover. Ran in with (243) joints of 2 7/8", P-110 CTR tubing. Rigged up power swivel. Tagged fish and reverse 2 tubing volumes at 5 bpm at 700 psi. Continued milling on (Baker) 7" Retieva D packer. Pumping 1 bpm Getting good cuttings back but still not making much hole. Looks like something is spinning with us possibly the rings in the element section. Got a little rubber in our returns. Reverse circulating at 1 bpm at 300 psi. Not making any hole. Reverse circulated 2 tubing volumes at 4 bpm at 1000 psi. Pulled high. Lost 20 bbl's of 8.5 ppg, 60 vis polymer this tour. Secured well till the AM.

Daily Operation Period: 2/16/2016 - 2/17/2016

Operations this Report Period (DOGGR)

Held safety meeting, Service rig. Field pressure = 924 psi, SITP = 0 psi, SICP = 0 psi. Open well. Filled hole with 4 bbl's of 8.5 ppg, 60 vis polymer. Continued milling on (Baker) 7" Retieva D packer. Dry milled on packer. Tried various speed and weight. No torque. Rigged down power swivel. Pulled out of the hole with (40) joints of 2 7/8", P-110 CTR tubing. Filled hole with 8.5 ppg, 60 vis polymer. Rig losing power. Secure well till the AM. Rig down due to electrical problem. Lost 4 bbl's of 8.5 ppg, 60 vis polymer this hour.

Daily Operation Period: 2/17/2016 - 2/18/2016

Operations this Report Period (DOGGR)

Ensign monthly safety meeting.Held safety meeting. Service rig. Field pressure = 927 psi, SITP = 0 psi, SICP = 0 psi. Open well. Filled hole with 4 bbl's of 8.5 ppg, 60 vis polymer. Finished repairs on rig. Continued pulling out of the hole with (222) joints of 2 7/8", P-110 CTR tubing. Broke down milling assembly and stood back drill collars. Shoe was worn but still had carbide on it. Made up new shoe. 6" X 5 3./4" mill shoe, 2' - 5 3/4" extension, 5 3/4" X 3 1/2" IF drive sub, 3 1/2" IF X 3 1/2" reg crossover, 5 7/8" boot basket, 3 1/2" reg X 3 1/2" IF sub, 4 3/4" jars, (4) 4 3/4" drill collars, 3 1/2" IF X 2 7/8" 8rd crossover, 2 7/8", 8rd X 2 7/8" CTR crossover. Ran in with (240) joints of 2 7/8", P-110 CTR tubing. Lost 4 bbl's of 8.5 ppg, 60 vis polymer this tour. Secured well till the AM.

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION
DIVISION OF OIL, GAS, AND GEOTHERMAL RESOURCES

Rec'd 10-13-16 DOGGR Ventura.

HISTORY OF OIL OR GAS WELL

Operator Southern California Gas Company Field Aliso Canyon County

Well Porter 35 Sec. 28, T3N, R16W, S.B.B.&M.

A.P.I. No. 03700722 Name Tom McMahon (Person submitting report) Title SIMP Project Manager (President, Secretary, or Agent)

Date 9/27/2016 (Month, day, year)

Signature

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Daily Operation Period: 2/18/2016 - 2/19/2016

Operations this Report Period (DOGGR)

Held safety meeting. Service rig. Field pressure = 969 psi, SITP = 0 psi, SICP = 0 psi. Open well. Filled hole with 2 bbl's of 8.5 ppg, 60 vis polymer. Picked up 3 joints of 2 7/8", P-110 CTR tubing. Rigged up power swivel. Started out dry milling. Reverse circulating at 1 bpm at 300 psi and 6K to 8K weigh on mill. Continued milling over (Baker) 7" Retieva D packer. Get getting a lot of metal back. Reverse circulated 2 tubing volumes at 5 bpm at 1000 psi. Pulled high. Lost 2 bbl's of 8.5 ppg, 60 vis polymer. Secure well till the AM.

Daily Operation Period: 2/19/2016 - 2/20/2016

Operations this Report Period (DOGGR)

Held safety meeting. Service rig. Field pressure + 999 psi, SITP = 0 psi, SICP = 0 psi. Filled the hole with 1 bbl's of 8.5 ppg, 60 vis polymer. Rigged down power swivel. Pulled out of the hole with (242) joints of 2 7/8", P-110 CTR tubing and milling assembly. Filling the hole every 10 stands with 8.5 ppg, 60 vis polymer. Broke down milling assembly and stood back drill collars. Broke off shoe. Shoe look good with only little wear. Made up new shoe and ran with 6" X 5 3./4" mill shoe, (2) 5 3/4" extension, 5 3/4" X 3 1/2" IF drive sub, 3 1/2" IF X 3 1/2" reg crossover, 5 7/8" boot basket, 3 1/2" reg X 3 1/2" IF sub, 4 3/4" jars, (4) 4 3/4" drill collars, 3 1/2" IF X 2 7/8" 8rd crossover, 2 7/8", 8rd X 2 7/8" CTR crossover. Ran in the hole on (242) joints of 2 7/8", P-110 CTR tubing. Picked up 3 joints of 2 7/8", P-110 CTR tubing. Rigged up power swivel and circulating head. Continued milling on (Baker) 7" Retrieva D packer. Pumping 1 bpm at 300 psi. Running various weights from 3K to 8K on shoe. Getting good metal shavings back. Reverse circulated 2 tubing volumes at 5 bpm at 1000 psi. Pulled high, Secured well till the AM.

Daily Operation Period: 2/20/2016 - 2/21/2016

Operations this Report Period (DOGGR)

Held safety meeting. Service rig. Field pressure = 1014 psi, SITP = 0 psi, SICP = 0 psi. Open well. Filled hole with 1 bbl of 8.5ppg, 60 vis polymer. Reversed circulated at 1 bpm at 250 psi. Continued milled on (Baker) 7" Retrieva D packer. Packer fill approximately 5'. Continued to mill on packer. Reversed circulated clean with 2 tubing volumes of 8.5 ppg, 60 vis polymer at 5 bpm at 1000 psi. Lost 1 bbl of 8.5 ppg, 60 vis polymer this tour. Secure well for the weekend.

Daily Operation Period: 2/22/2016 - 2/23/2016

Operations this Report Period (DOGGR)

Held safety meeting. Service rig. Field pressure = 1013 psi, SITP = 0 psi, SICP = 0 psi. Open well. Filled well with 5 bbl's of 8.5 ppg, 60 vis polymer. Reversed circulated at 1 bpm at 100 psi. Continued milling on (Baker) 7" Retrieva D packer. Made approximately 4". Circulated clean with 100 bbl's of 8.5 ppg, 60 vis polymer at 5 bpm at 1000 psi. Rigged out power swivel. Pulled out of the hole with (190) joints of 2 7/8", P-110 CTR tubing. Filling the hole every 10 stands with 8.5 ppg, 60 vis polymer. Lost 5 bbl's this tour. Secured well till the AM.

Daily Operation Period: 2/23/2016 - 2/24/2016

Operations this Report Period (DOGGR)

Held safety meeting. Service rig. Field pressure = 955 psi. SITP =0 psi, SICP = 0 psi. Filled the hole with 2 bbl's of 8.5 ppg, 60 vis polymer. Continued pulling out of the hole with (104) joints of 2 7/8", P-110 CTR tubing and milling assembly. Filling the hole every 10 stands with8.5 ppg, 60 vis polymer. Broke down milling assembly and stood back drill collars. Mill shoe showed signs of wear but in good condition. Made up fishing tools. Spear with 2.335" grapple, 5 1/2" stop sub, 2 3/8" IF X 3 1/2" IF crossover, 4 3/4" Bumper sub, 4 3/4" Jars, (4) 4 3/4" drill collars, 4 3/4" Slinger, 3 1/2" IF X 2 7/8" 8rd crossover, 2 7/8", 8rd X 2 7/8" CTR crossover. Ran in the hole on (243) joints of 2 7/8", P-110 CTR tubing. Rigged up circulating equipment. Pumping at 1 bpm at 200 psi. Tagged top of packer at 7,828' and speared. Jarred on packer, Able to work packer down. Jar on packer at 75K and pulling to 80K. Packer dragging. Hanging up at every casing collar having to jar out. Working packer out of the hole. Pulled (110) joints of 2 7/8", P-110 CTR tubing. Lost 2 bbl's of 8.5 ppg, 60 vis polymer this tour. Secure well till the AM.

Daily Operation Period: 2/24/2016 - 2/25/2016

Operations this Report Period (DOGGR)

Held safety meeting. Serviced rig. Field pressure = 908 psi, SITP = 0 psi, SICP = 0 psi. Open well. Filled the hole with 2 bbl's of 8.5 ppg, 60 vis polymer. Pulled out of the hole (126) joints of 2-7/8", P-110 CTR, Filled the hole every 10 stands with 8.5 ppg, 60 vis polymer. Fish was hanging up in each casing collar. Worked packer to 40K to 50K above string weight to release from casing collar. Packer would not pass 350'. Attempted to work fish past 350' with no success. Ran in the hole with (22) joints of 2 7/8", P-110 CTR tubing for a kill string. Lost 2 bbl's of 8.5 ppg, 60 vis polymer this tour. Secure well till the AM.

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Operator Southern California Gas Company Field Aliso Canyon County

Well Porter 35 Sec. 28, T3N, R16W, S.B.B.&M.

A.P.I. No. 03700722 Name Tom McMahon (Person submitting report) Title SIMP Project Manager (President, Secretary, or Agent)

Date 9/27/2016 (Month, day, year)

Signature

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Daily Operation Period: 2/25/2016 - 2/26/2016

Operations this Report Period (DOGGR)

Held safety meeting. Service rig. Field pressure = 968 psi, SITP = 0 psi, SICP = 0 psi. Open well. Filled the hole with 2 bbl's of 8.5 ppg, 60 vis polymer. Continue working packer out of the hole. Pulled (30) joints of 2 7/8", P-110 CTR tubing. Working packer through casing collars. Broke down fishing tools. Stood back drill collars and laid down Slinger, Bumper sub and Jars. Laid down spear and packer. Load out fishing tools. Rigged down power swivel.Tallied and made up (Weatherford) 7" scraper and Bumper sub and ran in on (248) joints of 2 7/8", P-110 CTR tubing. Tagged top of liner at 7,842'. (7,851' on program). Pulled out of the hole with scraper and (190) joints of 2 7/8", P-110 CTR tubing. Filling the hole every 10 stands with 8.5 ppg, 60 vis polymer. Secured well till the AM.

Daily Operation Period: 2/26/2016 - 2/27/2016

Operations this Report Period (DOGGR)

Held safety meeting. Service rig. Field pressure = 968 psi. SITP = 0 psi, SICP = 0 psi. Filled the hole with 2 bbl's of 8.5 ppg, 60 vis polymer. Pulled out of the hole with (58) joints of 2-7/8" P-110 CTR tubing, Laid down (1) Bumper sub, (1) 7" AW Scraper. Held pre-job safety meeting with Baker Hughes, Rigged up wire line unit and lubricator, Ran in the hole with Multi-finger caliper tool, Baker Hughes tagged @ 7853'. Logged well from 7852'-5800', Pulled out of the hole and laid down Multi-Finger Caliper tool, Ran in the hole with High Resolution Vertilog tool, Logged well from 0'-7843' and back up from 7843'-0', as High Resolution Vertilog tool was coming up through BOP tool hung up and parted @ cable head, Vertilog tool fell down hole, Rigged down lubricator and wire line unit, Laid down 4-3/4" Drill collars from derrick. Ran in the hole with (50) joints of 2-7/8" P-110 CTR tubing. Secured well till the AM.

Daily Operation Period: 2/27/2016 - 2/28/2016

Operations this Report Period (DOGGR)

Held safety meeting. Service rig. Field pressure = 957, SITP = 0 psi, SICP = 0 psi. Open well. Well standing full. Pulled out of the hole with (50) joints of 2-7/8" P-110 CTR tubing. Made up and Ran in the hole with 5-3/4" Overshot w/ 3-1/4" grapple, (1) 2-7/8" Nipple, (1) 4-1/2" Bumper sub, (1) 2-7/8" P-110 Pup Jt 8RD EUE, (1) 2-7/8" EUE X 2-7/8" TKC XO, (247) joints of 2-7/8" P-110 CTR tubing, Tag High Resolution Verti-log Tool (fish) @ 7813', engage fish with overshot, setting 12K down on fish. Pulled out of the hole with (247) joints of 2-7/8" P-110, (1) 2-7/8" EUE X 2-7/8" TKC XO, (1) 2-7/8" P-110 Pup Jt 8RD EUE, (1) 4-1/2" Bumper sub, (1) 2-7/8" Nipple, (1) 5-3/4" Overshot w/ 3-1/4" grapple, Over shot came back empty. Consulted with Baker Hughes wire line personnel and Weatherford Tool hand. Decision was made to run a 3-1/8" Grapple and make attempt to engage the Swivel of the High Resolution Verti-log tool. Made up and ran in the hole with 5-3/4" Overshot w/ 3-1/8" grapple, (1) 2-7/8" Nipple, (1) 4-1/2" Bumper sub, (1) 2-7/8" P-110 Pup Jt 8RD EUE, (1) 2-7/8" EUE X 2-7/8" TKC XO on (114) joints of 2-7/8" P-110 CTR tubing. Secured well for the weekend.

Daily Operation Period: 2/29/2016 - 3/1/2016

Operations this Report Period (DOGGR)

Held safety meeting. Service rig. Field pressure = 984 psi, SITP = 0 psi, SICP = 0 psi. Opened well. Filled the hole with 1 bbl of 8.5 ppg, 60 vis polymer. Continued running in the hole with (132) joints of 2 7/8", P-110 CTR tubing and fishing assembly.Picked up 1 joints of 2 7/8", P-110 CTR tubing and latched on to logging tools at 7,822'. Pulled 10k over string weight and fish pulled free. Pulled out of with (247) joints of 2 7/8", P-110 CTR tubing. Filling the hole every 10 stands with 8.5 ppg, 60 vis polymer. Laid down logging tools. Broke down and laid down fishing tools. (Baker) down loaded data from tools. Data was good. Made (Weatherford) 7" 23-29# Loc-Set bridge plug and ran in the hole on 2 7/8", P-110 CTR tubing. Set bridge plug at 1,023' and test to 400 psi for 5 minutes. Released and continue running in the hole with a total of (248) joints of 2 7/8", P-110 CTR tubing. Set bridge plug at 7,837' and released. Pulled (1) stand and test to 1000 psi for 5 minutes. Dumped 10' of sand and displaced with 44 bbl's of 8.5 ppg, 60 vis polymer. Pulled (40) joints of 2 7/8", P-110 CTR tubing. Secured well till the AM.

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Daily Operation Period: 3/1/2016 - 3/2/2016

Operations this Report Period (DOGGR)

Held safety meeting. Service rig. Field pressure = 964 psi, SITP = 0 psi, SICP = 0 psi. Open well. Well standing full. Continued pulling out of the hole with (208) joints of 2 7/8", P-110 CTR tubing. Laid down retrieving head. Made up (Weatherford) 7" 23-29# test packer. Ran in the hole on 2 7/8", P-110 CTR tubing. Set at 500' and tested casing annulus to 3625 psi for 30 minutes. Good test. Released packer and continued running in the hole. Set packer at 1000' and tested casing annulus to 3275 psi for 30 minutes. Good test. Released packer and continued running in the hole. Set packer at 1500' and tested casing annulus to 3100 psi for 30 minutes. Good test. Released packer and continued running in the hole. Set packer at 2000" and tested casing annulus to 2925 psi for 30 minutes. Good test. Released packer and continued running in the hole. Set packer at 2500' and tested casing annulus to 2750 psi for 30 minutes. Good test. Released packer and continued running in the hole. Set packer at 3350' and tested casing annulus to 2525 psi for 30 minutes. Good test. Test down the tubing from 3350' to BP at 7837' to 2450 psi for 30 minutes. Released packer. Pulled out of the hole with (106) of 2 7/8", P-110 CTR tubing and packer. Filled the hole every 10 stands with 8.5 ppg, 60 vis polymer. Broke out and laid down (Weatherford) test packer. Made up retrieving head and ran in the on (50) joints of 2 7/8", P-110 CTR tubing. Secure well till further notice.

Daily Operation Period: 3/7/2016 - 3/8/2016

Operations this Report Period (DOGGR)

Held safety meeting. Service rig. Field pressure = 1023 psi. SITP = 0 psi, SICP = 0 psi. Open well. Well standing full. Continue running in the hole with retrieving head and (198) joints of 2 7/8", P-110 CTR tubing. Laid down one joint and made up circulating equipment. Reverse circulated sand off of bridge plug at 7,837' two tubing volumes. Picked up one joint and release bridge plug. Reversed circulated out gas with 190 bbl's of 8.5 ppg, 60 vis polymer at 3.8 bpm at 1000 psi. Rigged out circulating equipment. Pulled out of the with (246) joints of 2 7/8", P-110 CTR tubing and bridge plug. Filling the hole every 10 stands with 8.5 ppg, 60 vis polymer. Laid down (Weatherford) bridge plug and retrieving head. Tallied and picked up a 45 mule shoe, 11 joints of 1 1/4", P-110, WTS-8 Hydril tubing, 1 1/4" X 2 7/8" 8rd crossover and ran in on (140) joints of 2 7/8", P -110 CTR tubing. Secured well till the AM.

Daily Operation Period: 3/8/2016 - 3/9/2016

Operations this Report Period (DOGGR)

Held safety meeting. Service rig. Field pressure = 1039 psi, SITP = 0 psi, SICP = 0 psi. Filled the hole with 1.5 bbl's of 8.5 ppg, 60 vis polymer. Continued running in the hole with (238) joints of 2 7/8", P-110 CTR tubing. Tagged liner top at 7,851', Rigged up circulating equipment. Reversed circulated at 2 bpm at 300 psi. Could not get in the liner. Tried rotating and circulating between reversing and the long way. Fell in the liner and tagged at 7,870'. Rotated and worked through several spots. Could not get past 7,919'. Continued rotating and circulating between reversing and the long way. Tagged again at 7,927'. Continued rotating and circulating between reversing and the long way. Could not get past 7,927'. Rigged down circulating equipment. Pulled out of the hole with (80) joints of 2 7/8", P-110 CTR tubing. Filled the hole every 10 stands with 8.5 ppg, 60 vis polymer. Lost 10 bbl's of 8.5 ppg, 60 vis polymer this tour. Secured well till the AM.

Daily Operation Period: 3/9/2016 - 3/10/2016

Operations this Report Period (DOGGR)

Held safety meeting. Service rig. Field pressure = 1048 psi, SITP = 0 psi, SICP = 0 psi. Open well. Filled well with 1.5 bbl's of 8.5 ppg, 60 vis polymer. Continued pulling out of the hole with (166) joints of 2 7/8", P-110 CTR tubing. Laid down 1 1/4" X 2 7/8" crossover, (11) joints of 1 1/4" WTS-8 Hydril tubing, 45 mule shoe. Made up (Weatherford) Loc-set bridge plug and ran in the hole on (40) joints of 2 7/8", P-110 CTR tubing. Set at 1,260' and tested to 500 psi for 10 minutes. Continued running in the hole with (208) joints of 2 7/8", P-110 CTR tubing. Tagged liner top @ 7,845'. Pulled up 15' and set at 7,830'. Test to 500 psi for 10 minutes. Dumped 10' of sand and displaced with 44 bbl's of 8.5 ppg, 60 vis polymer. Pulled out of the hole laying down (40) joints of 2 7/8", P-110 CTR tubing. Secure well till the AM.

Daily Operation Period: 3/10/2016 - 3/11/2016

Operations this Report Period (DOGGR)

Held safety meeting. Service rig. Field pressure = 1145 psi. SITP = 0 psi, SICP = 0 psi. Open well. Filled the hole with 1 bbl of 8.5 ppg, 60 vis polymer. Continued laying down (208) joints of 2 7/8", P-110 CTR tubing. Filling the hole every (20) joints with 8.5 ppg, 60 vis polymer. Laid down (Weatherford) retrieving head. Swap out trailers. Picked up (112) joints of 2 7/8", J-55 8rd blue band tubing. Open ended. Held BOP drill (41) seconds . Discussed well control procedures. Continue picking up tubing. Tubing tail at 3,390'. Secure well till the AM.

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Daily Operation Period: 3/11/2016 - 3/12/2016

Operations this Report Period (DOGGR)

Held safety meeting. Service rig. Field pressure = 1045 psi, SITP = 0 psi, SICP = 0 psi. Open well. Well standing full. Continued picking up (144) joints of 2 7/8", J-55, 8rd blue band tubing. Tagged top of sand at 7,814'. Laid down (2) joints and remove circulating head. Made up hanger and landed tubing. Tail at 7,778'. Screwed in lock screws and tested hanger to 500 psi for 10 minutes. Started rigging down and loading out equipment. Secure well till the AM.

Daily Operation Period: 3/12/2016 - 3/13/2016

Operations this Report Period (DOGGR)

Held safety meeting. Service rig. Field pressure = 984 psi, SITP = 0 psi, SICP = 0 psi. Open well. Nipple down 11", 5M annular and double gate BOP. Nippled up 2 9/16" 5M tree. Rigged up Cameron to test void. 300 psi low / 5000 psi high. No test. Tighten packing gland on hanger lock screws. Better but still no test. No visual leaks. Bled off air several times. Tried retesting a couple more times with no success. No visible leaks through the tree. Nippled down tree. Inspected ring grooves, API ring and extended neck seals. Installed new API ring and nippled up tree. Retest tree. Bled off air several times and retested. Good test 300 psi low and 5000 psi high. Rigged down Cameron. Rigged down rig. Rigged out the rest of the equipment. Ready to move to Fernando Fee 38C.

(254) joints of 2 7/8", J-55 8rd blue band tubing in well. Tail at 7,778.94'
(Weatherford) 7", 23-32# Loc-Set bridge plug at 7,830
Top of sand at 7,814'
Well full of 8.5 ppg, 60 vis polymer

Daily Operation Period: 4/6/2016 - 4/7/2016

Operations this Report Period (DOGGR)

Noise log indicated fluid movement down hole. Fluid Level shot after noise log indicated that the fluid level was at 2,600'.

Zero psi on the casing. 1 psi on the tubing. Started with 294 bbls 3% KCL polymer kill fluid in the 500 bbl tank.

Held safety meeting with HES and Onyx. Rig up Halliburton to pump 3% KCL polymer kill fluid from the 500 bbl tank down the tubing. Rig up Onyx choke and hard line from the casing to the 500 bbl tank. Pressure tested the pump and lines to 2,000 psi. Good. Pumped down the tubing with returns going to the 500 bbl tank at 5 bpm and 1,000 psi. Received immediate returns on the casing indicating that the well was standing full. Pumped a total of 302 bbls. (calculated circulating volume was 274 bbls). Shut pump down. No flow. Rigged HES and Onyx down. Secured the well

Re-strapped 500 bbl tank. Had 294 bbls remaining proving that the well was standing full prior to pumping.

Daily Operation Period: 7/19/2016 - 7/19/2016

Operations this Report Period (DOGGR)

MIRU 5000 psi test truck and iron to tubing wing valve. RU choke manifold to casing wing valve. RU vac truck to manifold and carbon canisters to vac truck.
Opened casing valve and topped off well with fluid by slowly pumping down tubing. With DOGGR representative on location, shut-in casing and pressured-up tubing to 600 psi.
Tested packer, tubing plug and casing for 1 hour. Test recorded digitally and with circle-chart. Test witnessed approved by DOGGR. Bled down pressure, shut-in well, RDMO

Ex. I – 50

BAKER HUGHES

HR Vertilog

Magnetic Flux Leakage Inspection

Advanced Analysis

Company	Southern California Gas Company
Well	Standard Sesnon 4A
Field	Aliso Canyon
County	Los Angeles
State	California
Location:	

Section 29	Township 3N	Range 16W	
Date	Sep. 17, 2016		
Service Order	US109335J		
Recorded by	Spencer / Gornto		
Witnessed by	Don Baldwin		
API Serial No.	04-037-21375		
Permanent Datum: G.L.	Elevation: 2885.580 ft.	Depth	3927.000
Log Measured From: K.B.	17.000 ft. above Perm. Datum	Btm. Log Interval	3927.000
Drilling Measured From: K.B.	17.000 ft. above Perm. Datum	Top Log Interval	0.000
		Fluid Type	KCL

Casing Data

Size	Weight	Grade	From	To	Length
8 5/8 inch	36.0 lb/ft	K55	-10.7	4065	4075.7

Equipment Data

Tool	7 to 9-5/8 Inch HRVRT 96 FL + 96 DIS Tool
Magnetizer	7 to 9-5/8 Inch HRVRT 96 FL + 96 DIS Tool
Telemetry	MUX-DB
Software Version	7.4.0.1

Calibration Data

Calibration File Name	4997-8-001-PB12116589-U.CAL
Date of Calibration	08/04/2016 13:46
Calibration Identifier	238470A8-E0BE-4D96-AD25-2408F0808DB5
Tool Number	4997-00
Calibrator Number	4997-8-001
Calibrator Size	(8-5/8 In - 219 mm)
Calibration Source File	20160804_131456_MEM.MVL
Calibration Software Rev	Microvision 32-bit 7.3.4.0
Comment	RMA1273

Calibration Data

Calibration File Name	4997-8-001-QA10409830-L.CAL
Date of Calibration	06/16/2016 16:01
Calibration Identifier	A00C9D82-DCC8-4973-8454-0F98E8079F2F
Tool Number	4997-00
Calibrator Number	4997-8-001
Calibrator Size	(8-5/8 In - 219 mm)
Calibration Source File	20160616_141623_MEM.MVL
Calibration Software Rev	Microvision 32-bit 7.3.4.0
Comment	RMA1333

In making interpretations of logs our employees will give customer the benefit of their best judgment. But since all interpretations are opinions based on inferences from electrical or other measurements, we cannot, and we do not guarantee the accuracy or correctness of any interpretation. We shall not be liable or responsible for any loss, cost, damages, or expenses whatsoever incurred or sustained by the customer resulting from any interpretation made by any of our employees.

Interpretation

26.21 ft Hardware - External casing head response.
934.10 ft Hardware - Bottom of 13 3/8"
1778.22 ft Hardware - Centralizer
1809.56 ft Hardware - Centralizer
2284.42 ft Hardware - Centralizer
2411.63 ft Hardware - Centralizer
2538.39 ft Hardware - Centralizer
2665.72 ft Hardware - Centralizer
2746.48 ft Hardware - Centralizer
2832.75 ft Hardware - Centralizer
2958.54 ft Hardware - Centralizer
3173.35 ft Hardware - Centralizer
3301.79 ft Hardware - Centralizer
3428.90 ft Hardware - Centralizer
3471.92 ft Hardware - Centralizer
3598.66 ft Hardware - Centralizer
3725.49 ft Hardware - Centralizer
3855.11 ft Hardware - Centralizer
3931.22 ft Hardware - Float Collar

Joint Interpretation Summary

Joint	From	To	Length	Class	Max Depth	Position	ID/OD
1	25.31	44.28	18.97	Class 1	-	-	-
2	44.28	86.94	42.66	Class 1	-	-	-
3	86.94	129.54	42.60	Class 1	-	-	-
4	129.54	172.54	43.00	Class 1	-	-	-
5	172.54	215.19	42.65	Class 1	-	-	-
6	215.19	258.50	43.31	Class 1	-	-	-
7	258.50	301.91	43.41	Class 1	-	-	-
8	301.91	344.44	42.53	Class 1	-	-	-
9	344.44	385.24	40.80	Class 1	-	-	-
10	385.24	427.18	41.94	Class 1	-	-	-
11	427.18	469.40	42.22	Class 1	-	-	-
12	469.40	511.79	42.39	Class 1	-	-	-
13	511.79	554.86	43.07	Class 1	-	-	-
14	554.86	596.68	41.82	Class 1	-	-	-
15	596.68	638.21	41.53	Class 1	-	-	-
16	638.21	681.48	43.27	Class 1	-	-	-
17	681.48	724.51	43.03	Class 1	-	-	-
18	724.51	767.26	42.75	Class 1	-	-	-
19	767.26	810.23	42.97	Class 1	-	-	-
20	810.23	853.24	43.01	Class 1	-	-	-
21	853.24	895.97	42.73	Class 1	-	-	-
22	895.97	938.72	42.75	Class 1	-	-	-
23	938.72	980.04	41.32	Class 1	-	-	-
24	980.04	1022.21	42.17	Class 1	-	-	-
25	1022.21	1063.37	41.16	Class 1	-	-	-
26	1063.37	1105.74	42.37	Class 1	-	-	-
27	1105.74	1148.25	42.51	Class 1	-	-	-
28	1148.25	1191.30	43.05	Class 1	-	-	-
29	1191.30	1233.83	42.53	Class 1	-	-	-
30	1233.83	1275.71	41.88	Class 1	-	-	-
31	1275.71	1318.40	42.69	Class 1	-	-	-
32	1318.40	1361.01	42.61	Class 1	-	-	-
33	1361.01	1402.61	41.60	Class 1	-	-	-
34	1402.61	1444.99	42.38	Class 1	-	-	-
35	1444.99	1485.48	40.49	Class 1	-	-	-
36	1485.48	1527.44	41.96	Class 1	-	-	-
37	1527.44	1570.72	43.28	Class 1	-	-	-
38	1570.72	1611.72	41.00	Class 1	-	-	-
39	1611.72	1654.76	43.04	Class 1	-	-	-
40	1654.76	1696.83	42.07	Class 1	-	-	-
41	1696.83	1735.42	38.59	Class 1	-	-	-
42	1735.42	1778.02	42.60	Class 1	-	-	-
43	1778.02	1820.19	42.17	Class 1	-	-	-
44	1820.19	1861.19	41.00	Class 1	-	-	-
45	1861.19	1903.88	42.69	Class 1	-	-	-
46	1903.88	1945.79	41.91	Class 1	-	-	-
47	1945.79	1989.41	43.62	Class 1	-	-	-
48	1989.41	2031.07	41.66	Class 1	-	-	-
49	2031.07	2074.25	43.18	Class 1	-	-	-
50	2074.25	2116.71	42.46	Class 1	-	-	-
51	2116.71	2157.22	40.51	Class 1	-	-	-
52	2157.22	2199.12	41.90	Class 1	-	-	-
53	2199.12	2241.88	42.76	Class 1	-	-	-
54	2241.88	2284.33	42.45	Class 1	-	-	-
55	2284.33	2326.33	42.00	Class 1	-	-	-
56	2326.33	2369.14	42.81	Class 1	-	-	-
57	2369.14	2411.73	42.59	Class 1	-	-	-
58	2411.73	2454.91	43.18	Class 1	-	-	-
59	2454.91	2497.59	42.68	Class 1	-	-	-
60	2497.59	2538.41	40.82	Class 1	-	-	-
61	2538.41	2581.31	42.90	Class 1	-	-	-
62	2581.31	2623.55	42.24	Class 1	-	-	-
63	2623.55	2665.79	42.24	Class 1	-	-	-
64	2665.79	2707.32	41.53	Class 1	16.0%	2701.81	ID
65	2707.32	2746.54	39.22	Class 1	-	-	-
66	2746.54	2789.75	43.21	Class 1	-	-	-
67	2789.75	2832.92	43.17	Class 1	-	-	-
68	2832.92	2874.75	41.83	Class 1	-	-	-
69	2874.75	2916.71	41.96	Class 1	-	-	-
70	2916.71	2958.71	42.00	Class 1	-	-	-
71	2958.71	3001.95	43.24	Class 1	-	-	-
72	3001.95	3045.32	43.37	Class 1	-	-	-
73	3045.32	3087.77	42.45	Class 1	-	-	-
74	3087.77	3130.53	42.76	Class 1	-	-	-
75	3130.53	3173.15	42.62	Class 1	-	-	-
76	3173.15	3216.01	42.86	Class 1	-	-	-
77	3216.01	3258.34	42.33	Class 1	-	-	-
78	3258.34	3302.04	43.70	Class 1	-	-	-
79	3302.04	3344.69	42.65	Class 1	-	-	-
80	3344.69	3386.51	41.82	Class 1	-	-	-
81	3386.51	3428.98	42.47	Class 1	-	-	-
82	3428.98	3472.16	43.18	Class 1	-	-	-
83	3472.16	3515.16	43.00	Class 1	-	-	-
84	3515.16	3555.96	40.80	Class 1	-	-	-
85	3555.96	3598.82	42.86	Class 1	-	-	-
86	3598.82	3640.66	41.84	Class 1	-	-	-
87	3640.66	3683.10	42.44	Class 1	-	-	-
88	3683.10	3725.56	42.46	Class 1	-	-	-
89	3725.56	3768.50	42.94	Class 1	-	-	-
90	3768.50	3811.93	43.43	Class 1	16.0%	3784.31	ID
91	3811.93	3855.17	43.24	Class 1	-	-	-
92	3855.17	3895.92	40.75	Class 1	-	-	-
93	3895.92	3933.19	37.27	Class 1	18.0%	3919.38	ID
94	3933.19	3948.81	15.62	Class 1	-	-	-

Southern California Gas Company Standard Sesnon 4A
File 20160917_09143D_RSP_0_0_0_0_0.mvl

Main Section
5"/100'

Class 1	Class 2	Class 3	Class 4
0 - 20%	20 - 40%	40 - 60%	60 - 100%

Southern California Gas Company Standard Sesnon 4A
File 20160917_09143D_RSP_0_0_0_0_0.mvl

Joint Summary

Southern California Gas Company
Aliso Canyon
Standard Sesnon 4A

Identifier	Start Log Depth ft	Joint Length ft	Diameter in	Wall Thickness in	Weight lb/ft	Max ML Depth %	Max ML Position ft	Min Burst Pressure psi	Joint Depth Class
JT-1	25.31	18.96	8.625	0.400	36.0	0			1
JT-2	44.28	42.66	8.625	0.400	36.0	0			1
JT-3	86.94	42.60	8.625	0.400	36.0	0			1
JT-4	129.54	43.00	8.625	0.400	36.0	0			1
JT-5	172.54	42.65	8.625	0.400	36.0	0			1
JT-6	215.19	43.32	8.625	0.400	36.0	0			1
JT-7	258.50	43.41	8.625	0.400	36.0	0			1
JT-8	301.91	42.53	8.625	0.400	36.0	0			1
JT-9	344.44	40.80	8.625	0.400	36.0	0			1
JT-10	385.24	41.93	8.625	0.400	36.0	0			1
JT-11	427.18	42.22	8.625	0.400	36.0	0			1
JT-12	469.40	42.40	8.625	0.400	36.0	0			1
JT-13	511.79	43.06	8.625	0.400	36.0	0			1
JT-14	554.86	41.82	8.625	0.400	36.0	0			1
JT-15	596.68	41.53	8.625	0.400	36.0	0			1
JT-16	638.21	43.28	8.625	0.400	36.0	0			1
JT-17	681.48	43.03	8.625	0.400	36.0	0			1
JT-18	724.51	42.74	8.625	0.400	36.0	0			1
JT-19	767.26	42.97	8.625	0.400	36.0	0			1
JT-20	810.23	43.02	8.625	0.400	36.0	0			1
JT-21	853.24	42.73	8.625	0.400	36.0	0			1
JT-22	895.97	42.75	8.625	0.400	36.0	0			1
JT-23	938.72	41.32	8.625	0.400	36.0	0			1
JT-24	980.04	42.17	8.625	0.400	36.0	0			1
JT-25	1022.21	41.16	8.625	0.400	36.0	0			1
JT-26	1063.37	42.37	8.625	0.400	36.0	0			1
JT-27	1105.74	42.51	8.625	0.400	36.0	0			1
JT-28	1148.25	43.05	8.625	0.400	36.0	0			1
JT-29	1191.30	42.52	8.625	0.400	36.0	0			1
JT-30	1233.83	41.89	8.625	0.400	36.0	0			1
JT-31	1275.71	42.69	8.625	0.400	36.0	0			1
JT-32	1318.40	42.60	8.625	0.400	36.0	0			1
JT-33	1361.01	41.60	8.625	0.400	36.0	0			1
JT-34	1402.61	42.38	8.625	0.400	36.0	0			1
JT-35	1444.99	40.49	8.625	0.400	36.0	0			1
JT-36	1485.48	41.96	8.625	0.400	36.0	0			1
JT-37	1527.44	43.27	8.625	0.400	36.0	0			1
JT-38	1570.72	41.00	8.625	0.400	36.0	0			1
JT-39	1611.72	43.03	8.625	0.400	36.0	0			1
JT-40	1654.76	42.07	8.625	0.400	36.0	0			1
JT-41	1696.83	38.60	8.625	0.400	36.0	0			1
JT-42	1735.42	42.60	8.625	0.400	36.0	0			1
JT-43	1778.02	42.17	8.625	0.400	36.0	0			1
JT-44	1820.19	41.01	8.625	0.400	36.0	0			1
JT-45	1861.19	42.69	8.625	0.400	36.0	0			1
JT-46	1903.88	41.91	8.625	0.400	36.0	0			1
JT-47	1945.79	43.62	8.625	0.400	36.0	0			1
JT-48	1989.41	41.67	8.625	0.400	36.0	0			1
JT-49	2031.07	43.18	8.625	0.400	36.0	0			1
JT-50	2074.25	42.46	8.625	0.400	36.0	0			1
JT-51	2116.71	40.51	8.625	0.400	36.0	0			1
JT-52	2157.22	41.90	8.625	0.400	36.0	0			1
JT-53	2199.12	42.76	8.625	0.400	36.0	0			1
JT-54	2241.88	42.45	8.625	0.400	36.0	0			1
JT-55	2284.33	42.00	8.625	0.400	36.0	0			1
JT-56	2326.33	42.82	8.625	0.400	36.0	0			1
JT-57	2369.14	42.59	8.625	0.400	36.0	0			1
JT-58	2411.73	43.18	8.625	0.400	36.0	0			1
JT-59	2454.91	42.68	8.625	0.400	36.0	0			1
JT-60	2497.59	40.81	8.625	0.400	36.0	0			1
JT-61	2538.41	42.90	8.625	0.400	36.0	0			1
JT-62	2581.31	42.24	8.625	0.400	36.0	0			1
JT-63	2623.55	42.24	8.625	0.400	36.0	0			1
JT-64	2665.79	41.53	8.625	0.400	36.0	16	2701.81	5904	1
JT-65	2707.32	39.21	8.625	0.400	36.0	0			1
JT-66	2746.54	43.21	8.625	0.400	36.0	0			1
JT-67	2789.75	43.18	8.625	0.400	36.0	0			1
JT-68	2832.92	41.82	8.625	0.400	36.0	0			1
JT-69	2874.75	41.97	8.625	0.400	36.0	0			1
JT-70	2916.71	42.00	8.625	0.400	36.0	0			1
JT-71	2958.71	43.24	8.625	0.400	36.0	0			1
JT-72	3001.95	43.37	8.625	0.400	36.0	0			1
JT-73	3045.32	42.45	8.625	0.400	36.0	0			1
JT-74	3087.77	42.76	8.625	0.400	36.0	0			1
JT-75	3130.53	42.62	8.625	0.400	36.0	0			1
JT-76	3173.15	42.86	8.625	0.400	36.0	0			1
JT-77	3216.01	42.32	8.625	0.400	36.0	0			1
JT-78	3258.34	43.71	8.625	0.400	36.0	0			1
JT-79	3302.04	42.65	8.625	0.400	36.0	0			1
JT-80	3344.69	41.81	8.625	0.400	36.0	0			1
JT-81	3386.51	42.47	8.625	0.400	36.0	0			1
JT-82	3428.98	43.18	8.625	0.400	36.0	0			1
JT-83	3472.16	43.00	8.625	0.400	36.0	0			1
JT-84	3515.16	40.79	8.625	0.400	36.0	0			1
JT-85	3555.96	42.86	8.625	0.400	36.0	0			1
JT-86	3598.82	41.84	8.625	0.400	36.0	0			1
JT-87	3640.66	42.44	8.625	0.400	36.0	0			1
JT-88	3683.10	42.45	8.625	0.400	36.0	0			1
JT-89	3725.56	42.94	8.625	0.400	36.0	0			1
JT-90	3768.50	43.43	8.625	0.400	36.0	16	3784.31	6006	1
JT-91	3811.93	43.24	8.625	0.400	36.0	0			1
JT-92	3855.17	40.75	8.625	0.400	36.0	0			1
JT-93	3895.92	37.27	8.625	0.400	36.0	18	3919.38	6002	1
JT-94	3933.19	15.61	6.625	0.352	24.0	0			1

Inspection Date: 09-17-2016
Report Date: 09-23-2016

Ex. I – 51

Due to the large file size, this exhibit is an excerpt. The native file of this document is available upon request.

Rec'd 05-04-17 DOGGR Ventura.

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION
DIVISION OF OIL, GAS, AND GEOTHERMAL RESOURCES

HISTORY OF OIL OR GAS WELL

Operator Southern California Gas Company Field Aliso Canyon County Los Angeles

Well Standard Sesnon 4 A Sec 28, T3N, R16W, S.B.B.&M.

A.P.I. No. 03721375 Name Tom McMahon (Person submitting report) Title SIMP Manager (President, Secretary, or Agent)

Date 4/26/2017 (Month, day, year)

Signature

Address PO Box 2300, SC9365, Chatsworth, CA 91313-2300 Telephone Number 714-398-5020

History must be complete in all detail. Use this form to report all operations during drilling and testing of the well or during redrilling or altering the casing, plugging, or abandonment, with the dates thereof. Include such items as hole size, formation test details, amounts of cement used, top and bottom of plugs, perforation details, sidetracked junk, bailing tests, and initial production data.

Start Date	Ops this Report (DOGGR)
9/22/2016	HSM: TOOH w/kill string. M/U SLB logging tools to log from 8217' to 3900' in 6 5/8" Csg. R/D & run kill string. Secure well - lock in rams & secure location.
9/23/2016	HSM; NOI issued. Pull kill string of 20 stands and M/U 6 5/8" RBP and RIH to 7980' and Set & sand off. TOOH and P/U Test Pkr. NOTE; Cliff Knight from DOGGR; Notified Engineering to set RBP at 8000' (just in top of MP) in order to get Work Permit Laydown test Pkr and RIH with RBP retrieving tool and circulate out sand. Unset RPB and move down 20' to 8000' (COE). Set and sand off. TOOH to killstring of 1250' & Shut in well
9/24/2016	HSM; Pull killstring w/RPB retrieving tool M/U a weatherford Arrow-set Pkr/On-Off tool and RIH t/ 8950' and set. R/U Pros and test Tbg to 1000 psi for 1 hr.-Good. Pull up and close in well & secure
9/26/2016	HSM; TOOH w/252 jnts. N/D Bope & install Tbg spool and test lower/upper seals-250 low & 1050 high. Good. N/U Bope & install Rig floor. Secure well and cleaned location.
9/27/2016	HSM; Spot in Weatherford BOPE Test truck and test Bope. RIH w/253 jnts of CRT tubing. Spot in pipe wrangler and TOOH sideways. Load out with Crane. Run kill string and secure well.
9/28/2016	HSM; Laydown CRT killstring and load out. Spot in 300 jnt of L-80 yellow band Tbg on racks. P/U On and Off tool, then RIH with 130 jnts of tbg utilizing the pipe wrangler. P/U Baker S.C. hydraulic Packer & continue to RIH w/75 jnts of Tbg. Secure well.
9/29/2016	HSM; Continued to RIH w/Baker straddle Pkr. Engage on/off tool & set S.C. Baker hydraulic Pkr @ 3991 (COE) and drop ball. Pressure up to; 1300/1600/2200 and set. Pressure Test Casing at 1000 psi for 1 hr and electronically chart. DOGGR; Curtis Welty-GOOD TOOH & lay down Baker retrieving tool. RIH t/ a kill string of 3843' and land Hanger. N/D BOPE and set aside. N/U Well head tree with No issues. Clean location-Set up to move Rig to Frew 4
9/30/2016	HSM; RDMO of SS4A and remove plates and clean cellar. Utilize (2) cranes to move off (large BOPE) and move to FREW 4 and set equip,
1/6/2017	COME BACK TO THIS WELL (HAD TO WAIT FOR HANGER TO BE MADE) HSM; 0 psi on well. Test BOPE to 300 low/5000 high psi. Move pump closer to Rig. Unland hanger & pull 83 jnts of Tbg. Secure well. DOGGR; Ernie Blevins here for BOPE inspection; Good
1/9/2017	HSM; 0 psi on well. Pull kill string. M/U Baker dummy seal tool and RIH t/3886' (126 jnts) and engage upper Pkr. R/U Wireline and RIH t/7928' & cut 2 7/8" Tbg. Good cut. (10 k in tension). TOOH w/wireline & R/D. M/U Pkr retrieving tool and RIH w/100 jnts of Tbg & Shut in well.
1/10/2017	HSM; 0 psi on well. Continue to RIH and engage 6 5/8" Hydraulic Pkr, on second attempt-sheared out @ 42 k over. TOOH slowly & layed down Pkr (good condition). M/U 4 11/16" Baker overshot w/bumper sub & RIH to Fish @ 8000' Half turn to right and unset Weatherford Pkr-pulled 20 stands. Secure well
1/11/2017	HSM; 0 psi on well. Added 3 bbls of fluid to well. Continue to TOOH w/2nd Pkr (Weatherford) & lay down. M/U retiieving tool & RIH t/7990' and circulate sand out. Engage 6 5/8" RBP and unset & let sit for 1/2 hr. Clean location for rain storm coming. Pull 50 jnts of Tbg. Secure well
1/12/2017	HSM; 0 psi on well. Continue to pull 6 5/8" RBP & laydown. M/U Weatherford 4.5" retrieving tool. RIH & circulated sand off. Engage RBP and unset/relax elements. Circulate 200 bbls and secure well
1/13/2017	HSM; 0 psi on well after unsetting 4.5" RBP. Fluid down @ 135'. Forward circulate any gas out. Bullhead high Vis pill of 25 bbls into liner. 4.5" RBP hanging up (tight area at 8717/rbp set at 8727') continue to TOOH, laydown bridge plug-3 elements missing. (Run 4.5" scraper). Run killstring & secure well.
1/17/2017	HSM; 0 psi on well. Cirulate 50 bbls of fluid-full returns. TOOH w/killstring. M/U 4" all weight scraper and RIH t/8244' (top of perfs) & unable to go further. TOOH & laydown scraper. P/U 2 3/8" mule shoe and RIH t/Kill sting depth. Secure well. NOTE; Construction requested to move our tanks/pump & support equip. to be able to trench. Will do tomorrow.

Rec'd 05-04-17 DOGGR Ventura.

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION
DIVISION OF OIL, GAS, AND GEOTHERMAL RESOURCES

HISTORY OF OIL OR GAS WELL

Operator Southern California Gas Company Field Aliso Canyon County Los Angeles
Well Standard Sesnon 4 A Sec 28, T3N, R16W, S.B.B.&M.
A.P.I. No. 03721375 Name Tom McMahon (Person submitting report) Title SIMP Manager (President, Secretary, or Agent)
Date 4/26/2017 (Month, day, year)
Signature
Address PO Box 2300, SC9365, Chatsworth, CA 91313-2300 Telephone Number 714-398-5020

History must be complete in all detail. Use this form to report all operations during drilling and testing of the well or during redrilling or altering the casing, plugging, or abandonment, with the dates thereof. Include such items as hole size, formation test details, amounts of cement used, top and bottom of plugs, perforation details, sidetracked junk, bailing tests, and initial production data.

Start Date	Ops this Report (DOGGR)
1/18/2017	HSM; Ensign Monthly Meeting in Valencia; 0 psi on well. Continue to RIH w/mule shoe & tag bottom @ 8737' with NO issues. TOOH and lay down mule shoe. P/U Baker Cast iron bridge plug. & RIH to kill string depth. **MOVE PUMP/2 Baker Tanks/plates for CONSTRUCTION to trench for laterals
1/19/2017	HSM; 0 psi on well. Continue to RIH s/Cast Iron bridge plug t/8227' & set. Pressure test to 500 psi and chart for 15 minutes. GOOD. TOOH to killstring depth. Shut in well. Off load 95 jnts of 4.5" inner string/Move Baker tank/re-position pipe wrangler. Slip & Cut Drilling line of 76'.
1/20/2017	HSM; 0 psi on well. Pull killstring & laydown the Baker Cast iron bridge plug setting tool. Have Weatherford change out Variable Rams to 4.5" Rams. Spot in Tong hand. HSM w/all personel to run 4.5" /513 inner string. Heavy winds/Rain. P/U shoe/FC & 30 joints of 4.5" inner liner and torque to specs. Close in well/secure location. NOTE; 5 fwy -snow on grapevine & rocks falling in roads to location
1/23/2017	HSM; Wait on Weatherford Tong hand. 0 psi on well. Continue to RIH w/67 jnts of 4.5" inner string & tally with shoe @ 8200' and hanger @ 3900'. Have Doby pull (3) cellars as they were Full. Heavy Rain/Hail. Circulate forward 100 bbls with no issues. Note; Rig mechanic to change out two clutch rams (sticking)
1/24/2017	HSM; 0 psi on well. Crane to position in Hanger. Change pipe rams back to VBR's. Off load 3.5" IF-DP. Spot in cement return tank. Utilize Ensign Gill -Drill pipe tongs. Not working correctly/rig down. Use Weatherford Drillpipe tongs. M/U Baker Hanger/bumper sub. Continue to RIH w/ 30 joints of 13.3# Drillpipe to 8 Klbs of torque. Shut in well.
1/25/2017	HSM; 0 psi on well. Continue to RIH w/hanger on DP. RIH w/95 jnts of Drill pipe. Attempt to pump down DP and pressured up. Discussed forward ops with Baker, Reverse circ. & try and free drill pipe scale on top of plug. Then forward circ and broke free. Circulated 120 bbls with no issues. Spot in Halliburton cement crew. Rig up Cement head to drill pipe. Baker drop ball down to landing collar ball seat @ 8150'. Pump total of 90 bbls of 8.6 ppg fluid down tubing. Set packer slips with 1800 psi. Blow ball seat @ 2400 psi. Release off packer. Pump 74 BBLS of 13.5/14.8 PPG lead cement (Premium G). Pump plug down with displacement of 93.5 bbls of 8.6 polymer fluid & bump plug @ 500 psi. Set Baker liner hanger packer @ 3897' and reverse out excess cement. Rig down Halliburton. Pull (5) stand & close in well
1/26/2017	HSM; 0 psi on well. Reverse Circ. 50 bbls. Continue TOOH sideways w/DP. Hydraulic line to tongs broke. Shut down and repair. Laydown all drill pipe & load out.(124 total). P/U 8 5/8" Scraper & bumper sub & RIH t/killstring depth. Shut in well
1/27/2017	HSM; HIGH WINDS/25-35 mph steady with gusts of 54 at RIG FLOOR. 0 psi on well. Continue to RIH w/scraper &14 stands of Tbg. Wind got worse-Unsafe & Shut in well. Stand by
1/30/2017	HSM; 0 psi on well. Continue to RIH w/scraper. Circulate 1.5 hole volume (250 bbls). TOOH. P/U 8 5/8" RBP and RIH & set at 860'/ pressure test, good. Sand off. TOOH and P/U Baker Packer and RIH, set @ 753'/ test backside-Good. Forward circulate and 0 psi @ 3.5 bbls/min. Secure well
1/31/2017	HSM; Reposition Packer, test-good. R/U cementers & pump 84 bbls of class III cement @ 1.5 bbls/min @ 44 psi. No returns. Pull up and reverse out. No returns. Attempt to fill hole. No good. Shut in well.
2/1/2017	HSM; 0 psi . RIH & set Pkr. Wait on Halliburton Cementers @ Ward 3. R/U Cementers and pump 90 bbls of class III cement w/ 2% Calcium chloride. 27 pis @ 2bbls a minute. TOOH-no signs of cement on tail. Shut in well. Order out more cement for tomorrow.
2/2/2017	HSM; 0 psi on well. RIH w/5 singles/Pkr and stand by for Halliburton cementers.R.U Cementers & HSM; Pumped 130 bbls of Class III cement w/2% Calcuim chloride & 7 bags of CC for the last 30 bbls. Pumped @ 1.5 bbls/min and final pressure was 222 psi. Got water returns between 13 3/8" & 8 5/8" Csg. Displace with 3.8 bbls & pulled out of hole. Filled hole and standing Full. Shut in blind rams & secure location.

Rec'd 05-04-17 DOGGR Ventura.

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION
DIVISION OF OIL, GAS, AND GEOTHERMAL RESOURCES

HISTORY OF OIL OR GAS WELL

Operator Southern California Gas Company Field Aliso Canyon County Los Angeles

Well Standard Sesnon 4 A Sec 28, T3N, R16W, S.B.B.&M.

A.P.I. No. 03721375 Name Tom McMahon (Person submitting report) Title SIMP Manager (President, Secretary, or Agent)

Date 4/26/2017 (Month, day, year)

Signature

Address PO Box 2300, SC9365, Chatsworth, CA 91313-2300 Telephone Number 714-398-5020

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Start Date	Ops this Report (DOGGR)
2/3/2017	HSM; 0 psi on well. Fluid level fell 1/2 bbl overnight., topped off. Applied 300 psi on 8 5/8" Csg., held-Good. RIH & Tag Cement @ 541'. TOOH & P/U Drilling assembly of 7 7/8" Bit/ (4) 4-1/16" Drill collars. RIH & tag cement. Pull up and circulate hole clean. Start drilling out cement with 2.5 power swivel @ 3 bbls/min. Drilled down to 652' of 845' (193' to go). Pulled up and circulate hole clean. Shut in well/secure location. NOTE; Repaired shaker screens for proper flow. Installed plates over SS-4 (from pressure/noise & temp log) and installed wrangler to run 6 5/8" Csg on Wednesday
2/6/2017	HSM; 0 psi on well. Continue to Drill out cement F/652' F/778' (126') & Power swivel started to leak excessivly hydraulic fluid. Shut down and changed out unit. Pull up and secure well.
2/7/2017	HSM; 0 psi on well. Continue to Drill out cement F/745' T/829'. Drill bit broke free, went down to sand @ 745' and circulated hole clean, above sand. TOOH & stand back collars/& laydown bit. P/U Scraper and RIH w/20 jnts. Close in well. NOTE: Moved Wrangler out and Pumped cellar/pump/shaker bin down. Pumped location of large puddles
2/8/2017	HSM; 0 psi on well. Continue to RIH w/scraper & tag RBP sand, pull up and circulate a hole volume. TOOH & laydown BHA. Spot in Doby Crane 30 ton & N/D BOPE. Remove old spool. Have welder dress 8 5/8" stub. Install 11" spool and test 300 low & 2750 psi High-GOOD. Install BOPE & Rig floor. P/U Baker retrieving tool and RIH w/ 20 stands of Tbg. Secure well.
2/9/2017	HSM: Continue to RIH w/retrieving tool & pull RBP. TOOH. P/U Pollish bore mill & RIH and pollish top of hanger. TOOH and prepare to Run 6 5/8" Casing tomorrow. Spot in wrangler and layout Casing. RIH with killstring.
2/10/2017	HSM; 0 psi on well. TOOH w/killstring. Change out VBR rams to 6 5/8". M/U BHA of a Baker seal assembly/Float shoe/Float collar jnt. (Baker lock 1st two jnts). Centrilize every other Jnt. RIH filling every 5 jnts. Torque to an average of 6500 ft/lbs. Had to wait for correct elevators. RIH w/19 joints with no issues. Rain increased where Seal Lube not insured. Close Rams and secure location.
2/13/2017	HSM; Continue to RIH w/6 5/8" inner string of 66 joints/ (1) pup & (1) 20' jnt to space out. Land on hanger at 3897'. Pressured up to 500 psi on the backside. GOOD. Close in well. Secure location.
2/14/2017	HSM; 0 psi on well. Wait on Halliburton cementers. Clean location for environmental inspection. Inspected-GOOD. Halliburton Cementers arrived at Noon. Spot in and Rig up. HSM & Pulled up 3' to expose hanger ports. Pump 20 bbls of Mud flush followed by 170 sxs of 13.5 ppg lead then 50 sxs of 14.8 ppg tail Cement (86 bbls total). Bumped plug at 123 bbls of displacement. Checked floats good. LAND SEAL with 20 k down then 10 k up. Set slips. Wash across spool and clean out lines. Drain BOPE & and install clam shell 6 5/8" Slips and set in place at spool. GOOD. Shut in well.
2/15/2017	MONTHLY ENSIGN SAFETY MEETING: HSM; 0 psi on well. Remove rig floor. Use 4 ways and remove Annular. Sling up double-gate and pull up. Slips at correct height, have Cameron torque down (12) bolts on slips. Replace double gate and close pipe rams. Secure location for weekend. Wait for Spool.
2/21/2017	HSM; 0 psi on well. Remove double-gate Bope. Cold cut 6 5/8" Csg for spool. Install spool & test (6) 300 low/5000 psi high-all good. Install X-over spool and N/U Bope. Close blind rams/Secure location.
2/22/2017	HSM; 0 psi on well. Weatherford changed pipe rams out. Test BOPE; blinds/annular/pipe rams of 300 low and 5000 high-Good. M/U 5.5/8" bit & 4 collars. RIH and tag cement @ 3805'. P/U swivel and drilled down (bridged off cement) to 3836'. Circulate clean. Shut in.
2/23/2017	HSM; 0 psi on well. Continue to drill out cement & plug-float collar F/3836' T/3890'. Circulate clean. Rig out power swivel. TOOH and laydown BHA. P/U 6 5/8" positive scraper and RIH w/62 jnt. and close in same.
2/24/2017	HSM; 0 psi on well. Continue to RIH w/scraper & tag hanger pull up and reverse circulate 100 bbls. TOOH and lay down BHA. RIH w/2 3/8" Hydril string and TOOH sideways. R/U and spot in wrangler to set out Tbg. RIH w/Killstring. Slip and cut 30' of Drilling line CASING TEST; Doggr - Curtis Willy to witness pressure test w/PROS. Pressure up to 4002 psi for 1 hr & decreased to 3923 psi (79 psi).GOOD. He signed chart/permit
2/27/2017	HSM; 0 psi on well. TOOH w/Tbg & laydown collars. Wait on tubing to be delivered via Doby. Offload 2 3/8" Tbg and strap. M/U 3 3/4" Bit and (4) drill collars with 121 jnts of Tubing. Obstruction at 3950' (FC rubbers-in 4.5"). R/U power swivel and shut in well. Secure location.
2/28/2017	HSM; 0 psi on well Continue to RIH pushing down rubbers from 6 5/8" FC. R/U power swivel and rotate down and circulate clean. R/D power swivel. RIH to 8140' and tag rubber/cement stringers. Circulate 150 bbls clean @ 2.3 bbls min. Pull up and rig out swivel for larger power swivel (Ensign). Secure well.
3/1/2017	HSM; 0 psi on well. Exchanged out power swivel from Weatherford to Ensign (more HP). Drilled out cement F/8110' T/8195'. Tagged cast iron bridge plug @ 8225'. Pulled up and circulated hole clean. Shut in well.
3/2/2017	HSM; 0 psi on well. Continue to circulate from 80 bbls of 150. Shakers clean. R/D Ensign powerswivel. TOOH w/25 stands. Winds increasing from 25 to 45 mph (50 in derrick-Tbg moving out of fingers) Close in well and standby for weather to subside.

Rec'd 05-04-17 DOGGR Ventura.

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Well Standard Sesnon 4 A Sec 28, T3N, R16W, S.B.B.&M.

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Start Date	Ops this Report (DOGGR)
3/3/2017	HSM; 0 psi on well. Continue to TOOH w/drilling assembly. Laydown BHA.(Drill Bit looks good 4/5-warn teeth from cement) M/U 4.5" scraper and RIH T/8150'. NOTE: 1 hour waiting on weather (34-42 mph winds in derrick). TOOH w/Scraper to killstring. Shut in well and secured location (containments).
3/6/2017	HSM; 0 psi on well. TOOH w/kill string and laydown 4" Scraper. R/U SLB lubricator and Log well. Made 2 runs F/8135' T/3900' (4.5" csg) & F/3900' to surface. R/D SLB. Run killstring and Shut in well.
3/7/2017	HSM; 0 psi on well. TOOH w/killstring. R/U SLB and continue to log last 250' to surface. R/U Baker Vertilog tool (Mag.Flux Leakage)- High Rez. 1st run in 4.5" Csg F/8135' T/3900'. TOOH and change tool and 2nd run in 6 5/8" Csg F3860' T/Surface. R/D. RIH w/killstring. Shut in well.
3/8/2017	HSM; 0 psi on well. TOOH w/killstring. R/U Baker wireline & run Caliper log in 4.5" Csg F/8235' T/Surface in (2) runs. R/D Baker. P/U drilling BHA of 3 3/4" drill bit (4) collars and RIH T/ 2 3/8" Tbg. on ground & 50 stands in derrick NOTE; FEMSA/SCG Management tour here to see logging unit in operation.
3/9/2017	HSM; 0 psi on well. Continue to RIH w/drilling assembly. Tight area around 3950'. Rotate through and tag Cast iron bridge plug @ 8225'. P/U Ensign power swivel and start drilling CIBP. WOB-2-4 k / 110 Rpm / 2 bbls-min. / 550 psi. Drilled out CIBP in 3 hrs. temporary lost returns and then re-gained back. Bridge plug fell to bottom & chased it down to (8695'-w/fill and bridge plug). Reverse circulated out gas. Pulled up to TOL & Shut in.
3/10/2017	HSM; 0 psi on well with bridge plug drilled out. On a vacuum. Plant a 20 bbl high vis pill at TOL. TOOH & lay down drilling BHA. NOTE: Drill bit intact and looked good. M/U Baker 3.80" string mill and RIH T/3926' and ream out rough spot after stacking out on it. Went through it 8 times. GOOD. TOOH sideway w/50 jnts of 2 3/8" Tbg. 110 jnts as kill string. NOTE: changed out Hydraulic hose for tongs under rig.
3/13/2017	HSM; 0 psi on well. Continue to TOOH sideways w/2 3/8" Tbg & string mill BHA. RIH w/254 jnts of 2 7/8" Tbg. TOOH sideways of 154 jnts of Tbg & left killstring in well of 100 jnts. Secure well & prep for running completions
3/14/2017	HSM; 0 psi on well. Continue to TOOH sideways w/2 7/8" Tbg & haul away. Offload 2 3/8" Tbg and strap. Added 22 bbls of fluid. M/U Weatherford Pkr /Xn nipple/SS/X profile and (2) jnts of Tbg. RIH & pressure test to 4100 psi. & chart. GOOD Continue to RIH /hydro test with 54 jnts of Tbg. Shut in well.
3/15/2017	HSM; 0 psi on well. Added 2 bbls of fluid. Continue to RIH w/ 2 3/8" Tbg w/seal lube. Offload and strap 125 jnts of 2 7/8" L-80 Tbg. P/U Hanger and M/U and close in rams
3/16/2017	HSM; 0 psi on well. Pumped 50 bbls of Pkr fluid and displaced w/25 bbls of polymer. Set 4.5" ASI-X Mech Pkr @ a COE of 8004' in 8.5 k-ft/lbs of Compression. Locked in lock down well head screws. DOGGR: Cliff Knight to witness; -Tested backside T/1000 psi for 1 Hr. GOOD. Wireline set PXN plug 1.875" & prong @ 8019'. TOOH & L/D wireline. -Pressured up Tubing and Tested to 3900 psi for 1 hr. Test Good NOTE; Sliding Sleeve Closed R/D rig floor and N/D BOPE & set out on truck. Install New Cameron Tree & close in same
3/17/2017	HSM; 0 psi on well. Cameron torqued tree & tested Wellhead seals 300 low / 5000 high. Good. Rig down support equipment and stage at SS-44B well. Tight location at SS-4A. NOTE: Plug installed and sliding sleeve closed/full of fluid. NOTE: ENSIGN to perform DOT 2 Rig inspection with Mechanics. Also change all Clutches out.
3/20/2017	MIRU Western wireline slickline unit. Ran 2' B shifting tool & opened sleeve at 7,935'. Pooh. C.W.I. R.D.M.O.
3/29/2017	MIRU & unloaded fluid w/ N2.
3/30/2017	Purged well bore. Applied pressure. retrieved prong & plug. Flow tested well. C.W.I. RDMO.
4/5/2017	SITP = 1,321 p.s.i. Opened & purged tbg. to attmoshere obtaining & confirming natural gas was at surface. Well went flat. C.W.I. & turned well over to operations

Rec'd 05-04-17 DOGGR Ventura.

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9/7/2016	DOGGR: Notified that we are on well and Permit in hand - plan forward; Ernie Blevins SCG: Control Room Notified were on Well SS4A- Nick Alderson Wireline; Removed PXN plug body @3896' MIRU- Placed Rig as to allow Construction to install Laterals/Trenches/support equip. for SS4B HSM; Tbg psi @ 1000 psi- bled down to 0 (slight flow) R/U & Pump High Vis HEC pill of 50 bbls & chase with a Tbg volume of 23 bbls Install BPV & NU Bope w/ variable double gate rams. Spot in pipe wrangler Secure location
9/8/2016	HSM: Repair Accumulator (power cord) & Test BOPE 5000 high/300 low with Variable Rams. Soft Dig back Anchors for Rig so as to have Construction get by with no Guy wire issues. Test all BOPE equip-Good Release from Otis J latch @ 3910' with no issues. Laydown Hanger and 1 jnt. Secure well. DOGGR: BOPE Inspection done by Curtis Welty from Cypress office; Good
9/9/2016	HSM: TOOH w/ 127 joints of 2 7/8" Tbg. Then have welder fabricate 3 lifters to pull 134 joints of 3 1/2" Flush Joint Tbg. Pulled 104 jnts of 3.5" utilizing the pipe wrangler, leaving 30 in hole for kill string. Had Cameron re dress the hanger Secure location
9/10/2016	HSM; Continue to pull 30 jnts of 3.5" F.J. Tbg and laydown. P/U 8 5/8" all weight scraper/bumper sub and RIH w/126 jnts of P-110 (2 7/8" tbg) to top of Permatrieve Pkr @ 3915' & tally in hole. Circulate on top of Pkr of 238 bbls clean. Pull 5 stands Secure well and location
9/12/2016	HSM; TOOH w/Scraper & L/D. P/U Weatherford Spear/Bumper Sub/Jars and RIH t/3915' & engage Permatrieve Pkr and pull out with No issues. TOOH and laydown (all intact) P/U a 6 5/8" all weight scraper and RIH with Tbg from Derrick and 50 jnt on the racks utilizing the pipe wrangler. Shut in and secure well
9/13/2016	HSM; Continue to RIH utilizing the pipe wrangler P/U from racks w/6 5/8" all weight scraper. Circulate on bottom a full well volume. TOOH & laydown scraper. P/U Fishing BHA and RIH t/6850'with no issues. Secure well
9/14/2016	HSM; RIH w/40 jnts of Tbg and engage permatrieve Pkr @ 8206' & jar out @ 40 k over. TOOH and laydown Pkr fully intact. P/U 2 1/16" clean out string of 20 jnts and RIH to TOL. Secure well.
9/15/2016	HSM; RIH w/Tbg to bottom @ w/2 1/16" Tbg and circulate 150 bbls. (no fill). TOOH & L/D 20 jnts of hydril Tbg. R/U SDI and Gyro Survey every 25' F/8737' T/GL. with no issues. R/D and run killstring. Secure well.
9/16/2016	HSM; Pulled killstring and R/U Baker Logging & Caliper logged F/8737' to surface. P/U 4.5" RBP and RIH set @ 8727' and sanded off. Pulled 10 stands and shut in well.
9/17/2016	HSM; TOOH w/250 jnts. R/U Baker Loggers & Log High Resolution F/3927' to Surface with no issues. RIH with killstring and secure well and location
9/19/2016	HSM; TOOH w/killstring. M/U lockset Pkr and RIH to Block Test the following intervals; A) 1000' at 3625 psi for 1 hr = Good B) 2000' at 3200 psi for 1 hr = Good C) 3000' at 2800 psi for 1 hr = Good D) 3900' at 2400 psi for 1 hr = Good DOGGR witness; Arsenio Laguazad and sign permit TOOH w/ Pkr and lay down. Run kill string and secure well and location
9/20/2016	HSM: RIH w/RBP and set @ 3900' & sand off. TOOH. N/D BOPE and remove Well head Spool to Cameron. Mark flanges for proper install for laterals. Install weatherford spool and N/U Bope. Install Rig floor. Close blind rams and secure location.
9/21/2016	HSM; Ensign Crew met at montly meeting in Valencia. Arrive on location. 0 psi on well. P/U retieving tool and RIH to sand at 3890' and clean out. Engage RBP and TOOH & L/D. R/U SLB lubricator and USIT log from 3900' to surface, re-log any anomolies. R/D and run killstring. Secure location.

Ex. I – 52

Well

Standard Sesnon 4A Orig. Hole & ST1

API #: 04-037-21375-00, -01
Sec 29, T3N, R16W

Operator: So. California Gas Co.

Lease: Standard Sesnon
Field: Aliso Canyon
Status: Active Gas Storage
3000TDS: ±800' (±797')
10000TDS: 2954' (2812')

Ground Elevation: 2885.58' asl
Datum to Ground: 17' KB

Spud Date: 11/12/1974
Completion Date: 3/15/1975
Last Rework Date: 3/20/2017

Junk: Cast Iron BP Milled & Pushed to 8695' (3/9/2017)

13-3/8" & 6-5/8" TOC Surface

8-5/8" ETOC 219'

17-1/2" Hole (to 962')

Surface Casing
13-3/8" (12.615" ID), 54.5#, K-55, BT&C
0' - 928' 928'

CMT'D w/ 500 CF + 150 SKS* + "Pumped 17 yds of 6 SK Pre Gravel Mix" Top Job

11" Hole (962' - 4665')

Inner CSG (2/14/2017)
6-5/8" (5.791" ID), 28#, L-80, BT&C
0' - 3897' (w/ Tie Back Seals & Ports)

CMT'D w/ 483 CF/220 SKS, 15 BBLS Returns to Surface

3897'

Production Casing
8-5/8" (7.825" ID), 36#, K-55, LT&C
0' - 4065'
4065'

CMT'D w/ 1140 CF

Inner Liner (1/25/2017)
4-1/2" (3.96" ID), 12.6#, L-80, Hydril 513
3897' - 8200'

CMT'D w/ 415 CF, CMT Returns to TOL

9-7/8" Hole (4665' - 6526')

CMT'D Liner
6-5/8", K-55, FJ
3927' - 4214' 24# (5.921" ID)
4214' - 5097' 28# (5.791" ID)
5097' - 8248' 24# (5.921" ID)

CMT'D w/ 493 CF* + SQZ'D TOL 5X's w/ total of 1069 CF Away (Calc'd)

8200'
8217'

7-5/8" Hole (6526' - 8248')

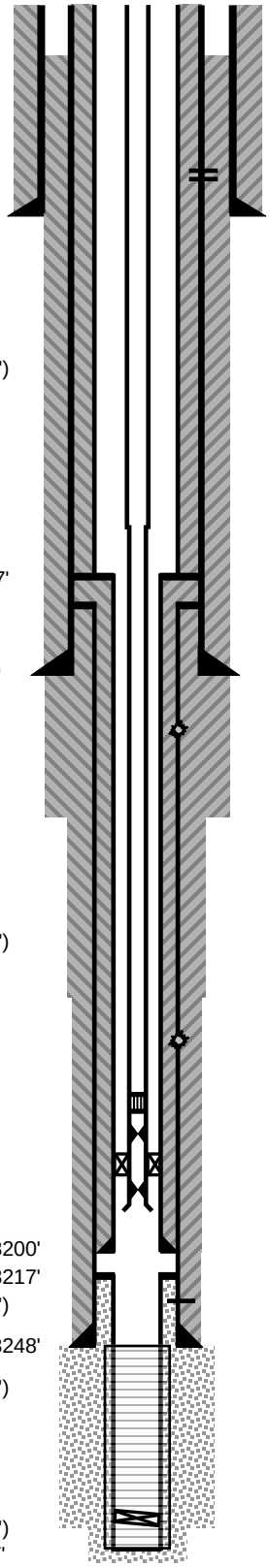
8248'

8" Hole (8248' - 8715')

WWS Liner
4-1/2" (4.0" ID), 11.6#, K-55, ST&C
8217' - 8737'

5-5/8" Hole (8715' - 8771')

TD 8771' 8737'
TVD (8153')
Directionally Drilled: Yes (TD is 2847' W, 597' N of Surf)



181' Sidetrack (ST1) KOP (f/ Orig. Hole) into this wellbore (see WB History)

815' - 825' Four (4) 1/2" HPF (SQZ'D 3x's w/ a total of 1611 CF CMT, Calc'd, SQZ'D Away, last SQZ had water returns btwn. 8-5/8" & 13-3/8", 1/31/2017)

Tubing (3/16/2017)
2-7/8" (2.441" ID), 6.5#, L-80, EUE
0' - 3786'
2-3/8" (1.991" ID), 4.7#, L-80, EUE
3786' - 8017'

3786' 2-7/8" x 2-3/8" X-Over

3897' 4-1/2" TOL & TOC

3927' 6-5/8" TOL & TOC (WSO, Appvd then SQZ'D w/ 50 SKS, 1/23/1975. WSO Re-Apprvd 1/28/1975)

4291' - 4296' Holes in 6-5/8" btwn. (25 SKS + 3 CF CMT SQZ'D Away, 1/13/1979)

7488' - 7518' Holes in 6-5/8" btwn. (2 CF CMT SQZ'D Away, 1/11/1979)

7926' WXO Sliding Sleeve (1.875" ID)
7961' WX Nipple (1.875" ID)
8001' WEA AS1-X PCKR (COE @ 8004', 3/16/17)
8016' WXN Nipple (1.875" w/ 1.791" No-Go)
8017' Wireline Re-entry Guide

8220' Four (4) 1/2" Holes WSO (1/18/1975) (20 SKS CMT SQZ'D, 1/19/75 + 100 SKS CMT SQZ'D, 1/27/1975)

4-1/2" Perfs:
8244' - 8737' Gru-V-Kut 0.018" Gauge

8695' Top of Junk/Fill (see desc. above)

Wellbore History

Orig. Hole (-00) TD @ 455'±
(11" Hole drifted 2' f/ IW-59 Cellar)
181' - 408' CMT Plug
(422 SKS, C/O f/ 134')
Sidetrack (ST1) KOP @ 181'
into current wellbore (-01)

Notes

Many problems w/ lost circ. during drilling. CMTing, WSO's obtained w/ difficulty

*No circulation throughout job

**No circulation while displacing CMT

Top of Zone Markers	md	(tvd)
PEupth	2954'	(2812')
FREWupth	4295'	(4029')
CRupth	4520'	(4239')
A36	5751'	(5401')
UP	6107'	(5738')
LP	6590'	(6186')
UDA1	6828'	(6406')
MDA	7402'	(6935')
LDA	7692'	(7195')
MP	7980'	(7449')
S1	8334'	(7766')
S4	8428'	(7851')
S8	8534'	(7945')
S14	8674'	(8069')

Prepared by: MAM (7/7/2016)
Updated by: LD (5/16/2018)

InterAct

Ex. I – 53

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION
DIVISION OF OIL, GAS, AND GEOTHERMAL RESOURCES

Rec'd 05-05-17 DOGGR Ventura.

HISTORY OF OIL OR GAS WELL

Operator Southern California Gas Company Field Aliso Canyon County Los Angeles
Well Porter 42 C Sec 28 3N 16W S.B.B.M.
A.P.I. No. 03721878 Name Tom McMahon (Person submitting report) Title SIMP Project Manager (President, Secretary, or Agent)
Date 1/19/2017 (Month, day, year)
Signature Thomas D McMahon
Address PO Box 2300, SC9365, Chatsworth, CA, 91313-2300 Telephone Number 714-398-5020

History must be complete in all detail. Use this form to report all operations during drilling and testing of the well or during redrilling or altering the casing, plugging, or abandonment, with the dates thereof. Include such items as hole size, formation test details, amounts of cement used, top and bottom of plugs, perforation details, sidetracked junk, bailing tests, and initial production data.

Start Date	Ops this Report (DOGGR)
9/26/2016	Well Shut in @ 30 psi SITP / 20 psi SICP. MIRU hoist and related equipment. Secured rig well and location.
9/27/2016	Well Shut in @ 30 psi SITP / 20 psi SICP.MIRU Onyx testers. Bled well to carbon filter cannisters. Killed well reversing 70 bbls of 3% KCL. Well @ 0 psi static.RDMO Onyx. Cameron installed BPV in tubing hanger. ND tree. NU BOPE. MIRU Weatherford testing. Tested BOPE and manifold according to GCS 224.05.
9/28/2016	Well shut in @ 0 psi SITP / 0 psi SICP. daily field pressure 1,263 psi. Unlocked BOPE. BOPE inspection approved by Doggr. Jay Hoff. Rigged up tubing swivel. Attempted to release HES J-latch packer seals@ 6,811'.Could not release packer or on-off tool. RU wireline attempted to cut tubing string unsuccessfully. CIW.
9/29/2016	Well shut in @ 0 psi SITP / 0 psi SICP. Daily field pressure 1,260 psi. RIH with freepoint on wireline.Tubing string was stuck @ GLM. Cut tubing string @ 6,671'. POOH with tubing,hanger pup joint. LD 110 joints of 3 1/2"N-80 tubing CIW and Secured.
9/30/2016	Well shut in @ 0 psi SITP / 0 psi SICP. Daily field pressure @ 1,263. Continued POOH laying down 3 1/2" N-80 production tubing. MU and RIH with Baker 8 1/8" waspipe, mill shoe,jars drill collars and 14 joint of 2 7/8" P110 to 662'. CIW.
10/1/2016	Well shut in @ 0 psi SITP / 0 psi SICP. Daily field pressure @ 1,265 psi. Continued RIH picking up 2 7/8" P110 workstring and Baker washpipe assembly. Tagged @ 6,741. Pulled up to 6,678'. CIW.
10/3/2016	Well shut in @ 0 psi SITP / 0 psi SICP. Reverse circulated 2 bbls p/m @ 0 psi annulus over GLM @ 6,718. Cleaned out light scale to 6,744'. Reversed 4.5 bbls p/m 60 bbls. POOH with washpipe. RIH with overshot and jars to retrieve 3 1/2" fish and GLM.
10/4/2016	Well shut in @ 0 psi SITP / 0 psi SICP. Daily pressure 1,268 psi. RIH with overshot. Jared on stuck 3 1/2" tubing and GLM. Could not jar free or rotate off of HES equipment. Released overshot from fish. POOH to kill string. Prepare for tubing cut in the am.
10/5/2016	Well shut in @ 0 psi SITP / 0 psi SITP. Daily field pressure 1,267 psi. POOH with kill string. RIH with full opening tools. Latched on to fish. Circulated clean 600 bbls. MIRU Tiger Wireline. RIH with 2.25" jet cutter. Attempted to cut stuck 3 1/2" tubing @ 6,748'. Cutter failed. RDMO wireline. CIW.
10/6/2016	Well shut in @ 0 psi SITP / 0 psi SICP. Daily field @ 1,267 psi. Released overshot and POOH. With CTR P110 work string and over shot. MU 8 3/8" crown shoe and 8 1/8" wash pipe and Baker assembly. RIH with 2 7/8" CTR P110 tubing to 6,663' , 11' above fish. CIW.
10/7/2016	Well shut in @ 0 psi SITP / 0 psi SICP. Daily firld @ 1,267 psi. RU power swivel and reverse circulated washing over fish from 6,674' to 6,814' w 8 1/8" washpipe.Cleaned out sand from 6,780' to top of packe HES packer @ 6,814'. POOH with washpipe assembly. MU 3.50" grapple in 5 3/4" overshot and bumpersub. RIH to kill string. CIW.
10/8/2016	Well shut in @ 0 psi SITP / 0 psi SICP. Daily field pressure 1,269 psi. RIH with work string and over shot to top of fish @ 6,671'. RU power swivel. Circulated and latched on to fish. Worked string attempting to release J-latch on HES packer. Tubing became free. POOH with P110 work string and overshot with cut tubing fish. RIH with kill string to1,289'.
10/10/2016	Well shut in @ 0 psi SITP / 0 psi SICP. Daily field @ 1,269 psi. POOH with kill string. MU Baker dress mill and assembly. RIH on 2 7/8" CTR P110. Tagged top of fish @ 6,748'. Milled on fish conventionally circulating @ 3 bbls p/m with 300 psi annulus.Milled to 6,751'. Let clean up. Returns showed light metal and KCL. POOH to 4,849'. CIW
10/11/2016	Well shut in @ 0 psi SITP / 0 psi SICP. Daily field pressure @ 1,269 psi. POOH with 2 7/8" work string and 8 1/8" dress mill with stabilizer. MU Baker 8 3/8" crown shoe and (3) joints of 8 1/8" washpipe and assembly. RIH to top of fish 6,751'. CIW.
10/12/2016	Well shut in @ 0 psi SITP / 0 psi SICP. Broke reverse circulation @ 3.5 bbls p/m. Washed over fish and tagged HES 9 5/8" WB packer @ 6,809'. Milled on packer with 8 3/8" shoe to 6,811'.Circulated clean metal and light scale. CIW.

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HISTORY OF OIL OR GAS WELL

Operator Southern California Gas Company Field Aliso Canyon County Los Angeles
Well Porter 42 C Sec 28 3N 16W S.B.B.M.
A.P.I. No. 03721878 Name Tom McMahon (Person submitting report) Title SIMP Project Manager (President, Secretary, or Agent)
Date 1/19/2017 (Month, day, year)
Signature
Address PO Box 2300, SC9365, Chatsworth, CA, 91313-2300 Telephone Number 714-398-5020

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Start Date	Ops this Report (DOGGR)
10/13/2016	Well shut in @ 0 psi SITP / 0 psi SICP. Daily field @ 1,268 psi. Continued milling on HES 9 5/8" WB packer from 6,811 to 6,811.5'. POOH with milling assembly. CIW.
10/14/2016	Well shut in @ o psi SITP / 0 psi SICP. Daily filed pressure @ 1,270 psi. Continued POOH with P110 tubing and Baker washover pipe / milling assembly.Changed shoe. RIH and continued milling on packer @ 6,812'. Pulled up. Circulated clean. CIW.
10/15/2016	Well shut in @ 0 psi SITP / 0 psi SICP. Daily field pressure @ 1,282 psi. Continued milling on HES 9 5/8" WB packer. Milled @6,812'. Could not make hole after 4 hrs of milling.Cleaned up reversing 150 bbls @ 4.00 bbls per min. CIW.
10/17/2016	Well shut in @ 0 psi SITP / 0 psi SICP. Daily field pressure 1,269 psi. POOH and laid down Baker BHA and mill shoe. MU new Baker overshot and BHA. RIH and latched on to fish @ 6,751'. Jarred on fish @ 100K over string. Tubing pulled free with 12K weight gain. POOH with tubing to 3,375'. CIW
10/18/2016	Well shut in @ 0 psi SITP / 0 psi SICP. Daily field pressure @ 1,269 psi. Continued POOH with work string and fishing BHA. RIH with new grapple and extension. Jarred on fish. Released on-off tool. POOH to kill string depth. CIW.
10/19/2016	Well shut in@ 0 psi SITP / 0 psi SICP. Daily field pressure @ 1,277 psi. Continued POOH with P110 tubing and Baker fishing BHA. LD cut 3 /12" tubing. sliding sleeve, 1 joint, pup and upper section of HES on-off tool. RIH with milling assembly to on-off. Milled lugs off HES on-off tool to 4.00" OD. Circulate clean. CIW.
10/20/2016	Well shut in @ 0 psi SITP / 0 psi SICP. Daily field pressure @ 1,266 psi. Rversed clean with tubing tail @ top of fish @ 6,806' (fish @ 6,808'). POOH with CTR P110 work string and Baker BHA. Wash shoe was heavily damaged and skim cut up one side.MU new 8 3/8" wash shoe with carbide. RIH with assembly to 4,706'. CIW.
10/21/2016	Well shut in @ 0 psi SITP / 0 psi SICP. daily field pressure @ 1,266 psi. Continued in hole with 2 7/8" CTR P110 work string and 8 3/8" mill shoe on washpipe. Tagged top fish @ 6,810. Milled over fish , milling skim cut shoe from previous run. Milled on HES 9 5/8" WB packer. Packer milled up and pushed free from 6,813 to 6,841'. Clean up POOH to 2,715'. CIW.
10/22/2016	Well shut in @ 600 psi SITP / 600 psi SICP. RU Carbon cannisters and and seperator to annulus. Pumped to tubing side. Vent annulus to cannisters on 18/24 choke while pumping 9.3# ppg 110 visc HEC polymer down tubing. Vent casing to 11 psi. Pumped 25 bbls of 9.3# HEC down casing. Well static. Installed tubing inside bope. Opened BOP RIH with and Baker BHA to 6,731'. Pumped 55 bbls of 9.3# 110 viscHECdown tubing folowed with 20 bbls of 8.5# 3% KCL. CIW. Secured rig,well and BOPE.
10/24/2016	Well shut in @ 0 psi SITP / 0 psi SICP. Unlocked BOP rams. POOH with 130 joints of CTR P110 workstring slowly to prevent swabbing formation. Pumped 1.5 bbls of 8.5# 3%kcl for tubing displacement. POOH to 2,700' and removed inline tubing checkvalve. Well was static. Continued out of hole with Baker BHA and washpipe with 8 3/8" shoe. MU 8 1/8" overshot with 4.00" grapple. MU Jars and BHA. RIH with 178 joints of 2 7/8" CTR P110 tubing to 5,751'. CIW. Secured.
10/25/2016	Well shut in @ 0 psi SITP / 0 psi SICP. Opened BOPE. RIH with remaining (28) joints of 2 7/8" P110 tubing. Latched on to fish @ 6,810'. Over pulled 20K. Pulled HES WB packer free. POOH with occational spot drag @ 10K to 12K over string. POOH to Baker fishing assembly. Retrieved seal,j-latch and tail section wwith pups and XN nipple. MU 4.961" grapple/spear and RIH. Engaged packer @ 4,670. Pulled 10k over and pulled free. Pulled 2 joints and worked trough casing collar with 15 over. Closed well in with tail @ 4,604.
10/26/2016	Well shut in @ 0 psi SITP / 0 psi SICP. Pumped well control fluids. Continued POOH with P110 workstring, Baker BHA with spear and HES WB packer remnant. MU 8 1/8" guide shoe, 1 7/8"grapple and CTR P110 tubing to 6,841". Tagged top of IJ tubing fish. Attempted to latch with rotation on tongs with poor results. CIW.

SUBMIT IN DUPLICATE

RESOURCES AGENCY OF CALIFORNIA
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DIVISION OF OIL, GAS, AND GEOTHERMAL RESOURCES

Rec'd 05-05-17 DOGGR Ventura.

HISTORY OF OIL OR GAS WELL

Operator Southern California Gas Company Field Aliso Canyon County Los Angeles
Well Porter 42 C Sec 28 3N 16W S.B.B.M.
A.P.I. No. 03721878 Name Tom McMahon (Person submitting report) Title SIMP Project Manager (President, Secretary, or Agent)
Date 1/19/2017 (Month, day, year)
Signature
Address PO Box 2300, SC9365, Chatsworth, CA, 91313-2300 Telephone Number 714-398-5020

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Start Date	Ops this Report (DOGGR)
10/27/2016	Well shut in @ 0 psi SITP / 0 psi SICP. RU circulating head and 2.5k power swivel. Pumped 1.00 bbls p/m 3% KCL down tubing while attempting to latch up 1 1/4" IJ tubing @ 6,841'. Worked tubing and overshot with light applied string weight and rotation. Attempted to latch up to fish. Attempts failed to latch fish. POOH with P110 and Baker BHA. Inspected grapple. RIH with cleanout string 2 1/16" Hydril & 2 7/8" P110. CIW.
10/28/2016	Well shut in @ 0 psi SITP / 0 psi SICP. Daily field pressure @ 1,274 psi. Continued in hole with Hydril 2 1/16" and 2 7/8" P110 cleanout string. Tagged fill inside 5 1/2" liner @ 7,503'. Mixed and pumped 60 bbls calcium carbonate pill for lost circulation. Pulled up to 6,878'. CIW.
10/29/2016	Well shut in @ 0 psi SITP / 0 psi SICP. Daily field @ 1,274 psi. Attempted to fill well with 3% KCL. Pumped down tubing @ 3 bbls p/m with 3% 8.5ppg KCL. Pumped theoretical casing volume of 533 bbls. Hole would not fill. Pulled tubing tail to 6,226'. RU to tubing and pumped 60 bbl. high visc 9.0# 36 pp/bbl saturated calcium carbonate plug. CIW.
10/31/2016	Well shut in @ 0 psi SITP / 0 psi SICP. Daily field pressure @ 1,275 psi. RIH with tubing to 7,503'. Tagged fill. Pulled up to 6,491'.Spot 80 bbls 10.0# 72# per barrel Calcium Carbonate pill. POOH with CTRP110 & 2 1/16" CS hydril string. MU Baker Kelo socket and fishing BHA with jars and RIH with 210 joints of CTR P110 to 6,828'. CIW.
11/1/2016	Well shut in @ 0 psi SITP / 0 psi SICP. Daily field pressure @ 1,276. Picked up 1 joint of P110 and rigged up power 2.5k swivel. Worked over 1 1/4" IJ tubing fish @ 6,844'. Pulled 8k over pull. POOH with tubing and BHA. Baker tool had failed and had damaage. RIH with overshot and new BHA. Latched up fish @ 6,845. Worked several times @ 30K overpull. POOH with 2K weight gain. POOH with tools to 4,479'. CIW
11/2/2016	Well shut in @ 0 psi SITP / 0 psi SICP. Daily field pressure @ 1,277 psi. Continued POOH with CTR P110 tubing and Baker BHA to fishing tools. Did not retrieve fish. MU Baker kelo socket and BHA. RIIH to top of fish. RU power swivel. Worked over fish to top of 7 5/8" liner. Could not get good over pull. Kelo socket kept pulling off. Hung back swivel. POOH with tubing to 3,500'+. CIW
11/3/2016	Well shut in @ 0 psi SITP / 0 psi SICP. Continued POOH with work string and Baker fishing tools. Inspected kelo socket and extension. MU and RIH with 1.90" grapple in 5 3/4" overshot 8 1/8" guide shoe and Baker BHS. RIH to Top of fish enagaged @ 6,842'. Worked to 6,872'. Pulled on fish.Unable to pull free. Backed of 1 1/4' fish. Gained 2k. POOH to kill string. CIW.
11/4/2016	Well shut in @ 0 psi SITP / 0 psi SICP. Daily field pressure @ 1,278. POOH with P110 tubing to Baker BHA. POOH with BHA to overshot and retrieved 26 joints of 1 1/4" IJ tubing. LD fish. MU and RIH with Baker 7 5/8" all weight casing scraper to top of 5 1/2" liner. Pumped 50 bbls 3% KCL to flush. No restrictions were encountered with scraper. POOH to 3,068'. CIW.
11/5/2016	Well shut in @ 0 psi SITP / 0 psi SICP. Daily field pressure @ 1,276 psi. Continued POOH with work string tallying and 7 5/8" AW casing scraper.MU 7 5/8" Baker RBP with unloader. RIH @ set RBP @ 7,450 COW. Filled casing with 3% KCL. Pressure teasted casing and RBP to 1,000 psi for 15 min. Good. POOH with (30) 6,480'. Dumped 10 cu. ft 100 mesh sand. Displaced with 43 bbls. CIW
11/7/2016	Well shut in @ 0 psi SITP / 0 psi SICP.Daily field pressure @ 1,277 psi. POOH with remaining (206) joints of 2 7/8" CTR P110 and Baker 7 5/8" retrieving tool. Filled casing with 10 bbls of 3% KCl while pulling. Casing standing full and static. LD Baker drill collars and loaded out all tools. LD 2 1/16" cleanout string. Prepared location for wireline casing integrity logs. CIW. Secured rig well and location.
11/8/2016	Well shut in @ 0 psi SICP. Standing full with 3% KCL.RBP set @ 7,450'. MIRU Baker Wireline. Ran Caliper Imagery /Verta Logs from 7,426' to Surface.Repeat runs from 7,410'. Loaded out logging tools RDMO Baker. CIW Secured.

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Start Date	Ops this Report (DOGGR)
11/9/2016	Well shut in @ 0 psi SICP. Daily field pressure @ 1,279 psi.Well standing full with 3% KCL. MIRU Schlumberger wireline services. Ran Usit / CBL logs on 9 5/8" and 7 5/8" casing from 7,400' to 6,868'. cahnged tools and logged from 6,868' to 22' /surface. CIW.
11/10/2016	Well shut in @ 0 psi SICP with annulus standing full 3% KCL RBP set @ 7,450'. RIH with 1,900' 2 7/8" tubing tail and Baker 9 5/8" Lok-Set Test packer. RIH w 2 7/8" CTR P110 tubing. Set packer @ 3,046'. Tested 9 5/8"casing above packer to 3,625 psi. Tested 9 5/8" and 7 5/8" casing below packer to 2,350 psi against RBP @ 7,450'. Test below packer on 7 5/8" would not test. Bled off 350 psi in 10 min. Chart / Digitally recorded test on 9 5/8" for 1hr @ 3,700 psi. Test on 9 5/8" witnessed and approved by Cliff Knight DOGGR. CIW .Secured.
11/11/2016	Well shut in @ 0 psi SITP / 0 psi SICP. daily field pressure @ 1,277 psi. Released Baker test packer.Ran down hole to 5,445'. Pressure tested casing tio 3,000 psi (good) for 15 min.POOH with tubing and tset packer. POOH laid down 1,900' tail. RIH with Test packer to 6,856' above 7 5/8" lap. Attempted to test casing and lap. Could not get solid test on digital gauge.Lost 159 psi in 30 mins. Pressure bled from 2,350 applied test pressure to 0 psi. CIW.
11/12/2016	Well shut in @ 0 psi SITP / 0 psi SICP. Daily field pressure @ 1,279 psi. Released Baker 9 5/8" test packer. Pulled up hole testing 30' intervals from 6,846' 6,815' 6,784; to 6,753. Solid test from 6,753' to surface. Released 9 5/8" test packer and POOH. RIH with kill string to 1,900'+. Plan forward to run RBP to 7 5/8" lap and pinpoint problem area with 9 5/8" packer.
11/14/2016	Well shut in @ 0 psi SITP / 0 psi SICP/ POOH with kill string. MU Baker 9 5/8" test packer. RIH with 10 joint tail. RIH to 6,790 attempted to test 9 5/8" caing lap nad 7 5/8" casing to RBP @ 7,490. Pressure tseted to 1,415 psi with 216 psi loss in 1hr. Moved RBP to 6,857 (10') above 7 5/8" lap @ 6,767'. Attempted to test with same results losing 75 psi in 15 min. CIW. Secured.
11/15/2016	Well shut in @ 0 psi SITP / 0 psi SICP. Daily field pressure @ 1,282 psi. Released 9 5/8" test packer @ 6.857'. POOH. RIH with 7 5/8" test packer to 6,877'. Tested 7 5/8" casing to 1,253 psi. tthrough tubing. Held pressure tset for 1hr with a pressure loss of 1 psi. 1,411 psi inital to 1,410 psi final (stabilized). Chart and digitally recorded.Test witnessed and approved by Randall Morlan Doggr.Bled pressure to 0 psi. Released test packer. CIW.
11/16/2016	Well shut in @ 0 psi SITP / 0 psi SICP, Daily field pressure 1,280 psi. PPOH with 7 5/8" test packer. RIH with 9 5/8" tset packer. Tested 9 5/8" casing @ 5,445' to 2,660 psi for 1hr. Pressure loss of (9) psi 2,651 psi final. Released and moved test packer down hole to 6,753'. Set and tested casing to 1,701 psi for 1 hr with pressure loss of (11) psi 1,690 psi final. Pros chart and digitally recorded tests. Tests were witnessed and approved by Doggr rep. Randall Morlan. Released test packer. CIW.
11/17/2016	Well shut in @ 0 psi SITP / 0 psi SICP. POOH with 9 5/8" test packer. MU and RIH with Baker retriving tool for 7 5/8" RBP. Circulated off sand cap @ 7,432' to RBP @ 7,450'. Latched up and let EQ. Released and let elements relax. POOH with RBP to 4,638' CIW
11/18/2016	Well shut in @ 0 psi SITP / 0 psi SICP. daily field pressure 1,283 psi. Continued POOH with 7 5/8" RBP. MU Baker fishing tools. RIH with 4 11/16" overshot and bumper sub,(237) joints of P110 tubing to 7,496'. Attempted to work into 5 1/2" liner with poor results. Notified engineering. POOH to 3,960'. CIW.
11/19/2016	Well shut in @ 0 psi SITP / 0 psi SICP. Daily field pressure. Continued POOH with Baker fishing tools. RIH with 7 5/8" Baker packer to 7,450' Set and established injestion rate 2.5 bbls p/m @ 150 psi, @ 3.0 bbls p/m @ 250 psi. Released packer and POOH to 4,016'+. CIW. Secured.
11/21/2016	Well shut in @ 0 psi SITP / 0 psi SICP. Daily field @ 1,284 psi. Continued POOH with CTR P110 work string and Baker 7 5/8" test packer. MU Baker 7 5/8" cement retainer. RIH and set @ 7,450' COE. Filled annulus and pressure tested to 500 psi. with bleed off due to lap and bad casing @ 6,753+. Established injection rate @ 2.5 bbls p/m with 150 psi and 3.0 bbls p/m @ 250 psi. with no visible increase or comunication to annulus above retainer. Stung out of retainer.CIW.Secured well and rig. EOT.

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION
DIVISION OF OIL, GAS, AND GEOTHERMAL RESOURCES

Rec'd 05-05-17 DOGGR Ventura.

HISTORY OF OIL OR GAS WELL

Operator Southern California Gas Company Field Aliso Canyon County Los Angeles
Well Porter 42 C Sec 28 3N 16W S.B.B.M.
A.P.I. No. 03721878 Name Tom McMahon (Person submitting report) Title SIMP Project Manager (President, Secretary, or Agent)
Date 1/19/2017 (Month, day, year)
Signature
Address PO Box 2300, SC9365, Chatsworth, CA, 91313-2300 Telephone Number 714-398-5020

History must be complete in all detail. Use this form to report all operations during drilling and testing of the well or during redrilling or altering the casing, plugging, or abandonment, with the dates thereof. Include such items as hole size, formation test details, amounts of cement used, top and bottom of plugs, perforation details, sidetracked junk, bailing tests, and initial production data.

Start Date	Ops this Report (DOGGR)
11/22/2016	Well shut in @ 0 psi SITP / 0 psi SICP. daily field pressure @ 1,285 psi. Reverse circulated 80 bbls of 3% KCL with retainer stinger @ 7,440' Retainer @ 7,450' MIRU Halliburton cement services. Pumped 1.8 ppg Xhem-Plug cement with super CBL additive. Stung into retainer @ 7,450. Pumped 12 bbls of cement slurry below. Final pressure @ 16 psi. Unstung from retainer @ pumped 10 bbls cemt balancing 200' plug from 7,450 to 7,250'. Dispaced with 9 bbls fresh. Pulled up to 71,00'. Reverse circulated 40 bbls of 3% KCL. Retrieved 1/4 bbls cement. Shut down pump. POOH with 34 joint to 6,030'. Reverse circulated 55 bbls of clean #% with no cement residual in returns. CIW. Secured. Released Halliburton services.
11/23/2016	Well shut in @ 0 psi SITP /0 psi SICP. daily field @ 1,285 psi. opened up BOPE. RIH with 2 7/8" CTR P110 tubing with Baker cement retainer stinger tail. Tagged top of cement @ 7,259' with 5K applied string weight. Tag witnessed and approved by Doggr representative Ernie Blevins. Pulled tubing tail up to 6,960+. Cleared tubing tail with 20 bbls of 3% KCL @ 3.0 bbls p/m with excellent returns. CIW. Secured rig and well. EOT
11/28/2016	Well shut in @ 0 psi SITP / 0 psi SICP. daily field 1,286 psi. Unlocked BOPE. Filled hole with 5 bbls KCL. Reverse circulated 20 bbls. Pressure tested annulus to 1,300 psi. Pressure loss to 7 5/8" lap @ 185 psi in 10 min. Bled to 0 psi POOH with 2 7/8" P110 tubing and Baker stinger. MIRU Western Wireline. Perforated 4 spf 1/2" squeeze holes from 7,208' to 7,218'. RIH with open ended tubing to 7,255'. MIRU Halliburton.Mixed and pumped 70 sx. (23) bbls of 14.8 ppg Chem-Plug cement. Displaced with 38 bbls of fresh water. Tubing volume 41 bbls. Balanced cement plug from 7,255' to 6,753'. POOH to 6,464'. Reversed clean with 60 bbls of 3% KCL. Recovered 1/4 bbls of cement. Closed kelly and pressured annulus to 1,000 psi in 200 psi increments. Final squeeze pressure @ 1,100 psi. Squeezed 1.6 bbls behind pipe. theoretical TOC @ 6,786'. CIW. Secured.
11/29/2016	Well shut in @ 0 psi SITP / 0 psi SICP. RIH with tubing and tagged TOC @ 6,852'. Pulled up and circulated clean. RIH and tagged TOC for Doggr representative Ernie Blevins. Witnessed and approved. MIRU Halliburton cementing services. Mixed and pumped 32sx. 10 bbls of14.8 ppg Chem Plug cement. Displaced with 37 bbls of fresh water. Balanced plug from 6,852' to 6,627' (225'). POOH to 6,464'. Reversed clean with 60 bbls of 3% KCL. Recovered grey water only. POOH with (202) joints of 2 7/8" tubing. MU 8 1/4" tri cone bit. RIH with (162) joints to 5,142'. CIW Secured.
11/30/2016	Well shut in @ 0 psi SITP / 0 psi SICP. RIH with (50) joints of 2 7/8" tubing from 5,142' to tag TOC @ 6,711'. Doggr rep Ernie Blevins witnessed. Discussed with engineering and Doggr reviewed well history and logs. Decision was made to bring TOC to above 6,600'. POOH with tubing and bit. RIH with open ended tubing to TOC @ 6,711'. Prep. to pump balanced cement plug to 6,520' in the am. CIW.
12/1/2016	Well shut in @ 0 psi SITP 0 psi SICP. Daily field pressure @ 1,284. Tagged TOC @ 6,711'. Reversed clean with 90 bbls of 3% KCL. MIRU Halliburton. Mixed and pumped 42 sx. 76 cu/ft 13.5 bbls of 14.8 ppg Chem-Plug cement. Displaced with 37 bbls. Balanced cement plug in 9 5/8" 53.5# from 6,711' to 6,520' TOC. Pulled tubing to 6,400'. Reversed clean with 80 bbls of 3%. Recovered grey water only. Released Halliburton. POOH with (202) joints total. RIH with 8 3/8" bit (202) joints to 6,400'. CIW Secured.
12/2/2016	Well shut in @ 0 psi SITP / 0 psi SICP. Daily field. RIH with (4) joints of 2 7/8" CTR P110 tubing and tagged TOC @ 6,538'. Pulled (2) joints and circulated 200 bbls while waiting on Doggr rep. Rigged out kelly. RIH and tagged TOC @ 6,538 for doggr. Pressure tested casing and cement to 1,100 psi. Chart and digitally recorded with Pros testing. Held pressure @ 1,098 psi with 16 psi pressure drop in 1hr to 1,082 psi final. Tag and test witnessed and approved by Curtis Welty. Bled to 0 psi. RDMO Pros. POOH laying down (150 joints of 2 7/8" tubing. CIW. Secured with tail @ 1,791. EOT.
12/5/2016	Well shut in @ 0 psi SITP / 0 psi SICP. Continued POOH laying down P110 work string. Tallied and RIH with open ended 2 7/8" J-55 tubing to 1,572'. Landed tubing hanger. Secured rig. Prepared for ND, NU, test and RDMO. Secured rig well and BOPE.

RESOURCES AGENCY OF CALIFORNIA
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Rec'd 05-05-17 DOGGR Ventura.

HISTORY OF OIL OR GAS WELL

Operator Southern California Gas Company Field Aliso Canyon County Los Angeles
Well Porter 42 C Sec 28 3N 16W S.B.B.M.
A.P.I. No. 03721878 Name Tom McMahon (Person submitting report) Title SIMP Project Manager (President, Secretary, or Agent)
Date 1/19/2017 (Month, day, year)
Signature
Address PO Box 2300, SC9365, Chatsworth, CA, 91313-2300 Telephone Number 714-398-5020

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Start Date	Ops this Report (DOGGR)
12/6/2016	Well shut in @ 0 psi SITP / 0 psi SICP. Tubing hanger landed and secured with open ended tubing tail @ 1,572. Daily field pressure @ 1,290 psi. Insatlled BPV in tubing hanger. ND Class III bope. Installed WKM 3 1/8" 5000 psi master valve. Pressure tested 300 / 5000 and chart recorded (good). Bled to 0 psi. RDMO Cameron. RDMO rig and all support equipment. Loaded out and moved off. Cleaned location released to operations.

Ex. I – 54

Rec'd 05-04-17 DOGGR Ventura.

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION
DIVISION OF OIL, GAS, AND GEOTHERMAL RESOURCES

HISTORY OF OIL OR GAS WELL

Operator Southern California Gas Company Field Aliso Canyon County Los Angeles

Well Ward 3 A Sec. 27, T3N, R16W, S.B. B&M

A.P.I. No. 03722306 Name Tom McMahon (Person submitting report) Title SIMP Manager (President, Secretary, or Agent)

Date 4/27/2017 (Month, day, year)

Signature

Address PO Box 2300, SC9365, Chatsworth, CA 91313-2300 Telephone Number 714-398-5020

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Start Date	Ops this Report (DOGGR)
11/30/2016	Safety meeting. (vehicle or heavy equiment). Serivce rig and equipment. Field pressue 1287-psi-Continue RIH w/180-jts of 3.5" tbg T/ 7178'-Roll tbg on plastic. Spot power swivel on containment-R/U pwer swivel. P/U 1-jt of 3.5" tbg. Pump 80-bbls of high vis polymer, displace w/ 50-bbls. Rotate tbg w/ swivel and Cut 3.5" tbg @ 7210'- R/D power swivel. L/D 1-jt of 3.5" tbg. Fill casing w/ 29-bbls of polymer-POOH w/ 226-jts of 3.5" tbg, x/o, (4) DC, Bushing, L/D 2-jts of 6" wash pipe, L/D cut 3.5" tbg, L/D 6" cutter-RIH w/ 5.75" overshot loaded w/ 3.5" grapple, LBS, Jar, (4) 4.75" DC, Slinger, X/O, 48-jts of 3.5" tbg, to 1620'-SWI. Secure well and rig.
12/1/2016	Safety meeting. (crane and lifting equipment). Serivce rig and equipment. Field pressue 1284-psi-Continue RIH w/180-jts of 3.5" tbg, p/u 8' pup jt. Ingage fish @ 7210'-Jar on seals, start @ 120k and work up to 130k no movement-Release overshot. L/D 2-jts and 8' pup jt-POOH w/ 178-jts of 3.5" tbg, tail @ 1620'-SWI. Secure rig.
12/2/2016	Safety meeting. (High Winds). Serivce rig and equipment. Field pressue 1284-psi-Windy conditions, 35-mph, Stand by. Shut down due to windy conditions.
12/5/2016	Safety meeting. (fire hazard). Serivce rig and equipment. Field pressue 1289-psi-Continue POOH w/ 48-jts of 3.5" tbg, X/O, L/D slinger, stand back (4) DC, L/D Jar and LBS, L/D overshot-RIH w/ 7-1/2" x7-3/8" shoe, 1-jt of 7-3/8" wash pipe, Bushing, X/O, (4) 4-3/4" DC, X/O, 228-jts of 3.5" tbg T/ 7225'-N/U flange and circulating head. P/U Power swivel. P/U 1-jt of 3.5" tbg, tag @ 7228'-Begin milling over packer F/ 7228'. It takes 3200 ft lbs to 4000 ft lbs to rotate tools. Pull up to 7225'. Reverse 2x tbg volume-SWI. Secure well and rig.
12/6/2016	Safety meeting. (slips, trips, falls). Serivce rig and equipment. Field pressue 1289-psi-R/D power swivel, N/D flange and PGSR. L/D 5-jts of 3.5" yellow tbg. Move power swivel off location-Move wash pipe trailer off loaction. Spot Weatherford L/D trailer on containment. Spot pipe racks on plastic-POOH L/D 184-jts of 3.5" tbg, tail @ 1541'. Note: Rotate tbg @ 6080', 1800 ft lbs. Rotate tbg @ 4968', 1400 ft lbs. Rotate tbg @ 4077', 1200 ft lbs. Rotate tbg @ 2967', 700 ft lbs-SWI. Secure well and rig.
12/7/2016	Safety meeting. (pinch points). Serivce rig and equipment. Field pressue 1283-psi-Continue L/D 40-jts of 3.5" tbg-Crane loading 224-jts of 3.5" tbg from pipe racks onto trailers-Crane unloading 246-jts of 3.5" PH/6 tbg from trailers to pipe racks. Tally tbg-RIH P/U 48 jts of 3.5" PH/6 tbg, tail @ 1650'- SWI. Secure well and rig.
12/8/2016	Safety meeting. (working w/ chemicals). Serivce rig and equipment. Field pressue 1286-psi- Contiue RIH P/U 179-jts of 3.5" PH/6 tbg, tail @ 7221'-Move pipe racks and pipe wrangerler. Spot pipe trailer and power swivel-SWI. Secure well and rig.
12/9/2016	Safety meeting. (heat /cold stress). Serivce rig and equipment. Field pressue 1289-psi-N/U flange and circulating head. P/U Power swivel. P/U 1-jt of 3.5" tbg, tag @ 7228'-Begin milling over packer F/ 7228' T/ 7230'. Packer stuck in wash pipe. Come up and Unable to go down-R/D power swivel, N/D flange and PGSR. L/D 2-jts of 3.5" tbg-POOH slow w/ 178-jts of 3.5" tbg, tail @ 1667'-SWI. Secure well and rig.
12/12/2016	Safety meeting. (vehicle or heavy equipment). Serivce rig and equipment. Field pressue 1289-psi-Ajust containment under swivel and pipe trailer-Continue POOH w/ 48-jts of 3.5" tbg, X/O, 4-DC, bushing, L/D 1-jt of wash pipe and 1-shoe. Found thin pieces of metal in wash pipe-RIH w/ 5.75" overshot loaded w/ 3.5" grapple, LBS, Jar, (4) 4.75" DC, Slinger, X/O, 228-jts of 3.5" tbg. Ingage fish @ 7211'. Packer draging up hole. L/D 2-jts of 3.5" tbg-Slowly POOH w/ 108-jts of 3.5" tbg, tail @ 3828'-SWI. Secure well and rig.
12/13/2016	Safety meeting. (overhead utilities). Serivce rig and equipment. Field pressue 1291-psi-Continue POOH w/ 118 jts of 3.5" tbg, x/o, Slinger, (4) DC, strip on 8-5/8" casing stub, POOH w/ jar, LBS, overshot and fish. L/D cut piece, seals and packer-Unload sracper from trailer. RIH w/ 8-5/8" scraper, bumper sub, (4) 4.75" DC, X/O, 226-jts of 3.5" tbg, P/U 5-jts of 3.5" tbg, tag TOL @ 7278'. L/D 1-jt of 3.5" tbg-POOH w/ 90-jts of 3.5" tbg, tail @ 4480'-SWI. Secure well and rig.
12/14/2016	Safety meeting. (crane and lifting equipment). Serivce rig and equipment. Field pressue 1291-psi-Continue POOH w/ 140-jts of 3.5" tbg, L/D (4) DC on trailer w/ crane, L/D BS and scraper-Load all Weatherford fishing equipment, collars and fishing baskets. Send back to Weatherford-Load out power swivel and spot off location on containment-Off load 15-jts of 2-1/16" tbg and all handling equipment. Tally 15-jts of 2-1/16" tbg-RIH w/ 2-1/16" pup jt and 15-jts of 2-1/16" tbg, x/o's, 218-jts of 3.5" tbg, tail @ 7250'-SWI. Secure well and rig.
12/15/2016	Safety meeting. (underground utilities). Serivce rig and equipment. Field pressue 1291-psi-Continue RIH w/ 13-jts of 3.5" tbg, tag fill @ 7644'. N/U flange and circulating head-C/O fill F/ 7644' T/ 7671'. Reverse 3X tbg volume @ 7671'- L/D 2-jts of 3.5" tbg, N/D flange and PGSR-POOH w/ 230-jts of 3.5" tbg, x/o, L/D 15-jts of 2-1/16" tbg and pup jt-RIH w/ 40-jt kill string, tail @ 1246'-SWI. Secure well and rig.
12/16/2016	Safety meeting. (watch for rock in road after heavy rain). Serivce rig and equipment. Field pressue 1291-psi-POOH w/ 40-jt kill string-N/U X/O flange and shooting flange-R/U DI Drill survey truck. Survey F/ surface T/ 7671'POOH. R/D DI drill-N/D X/O flange and shooting flange-RIH w/ 8 -5/8" RBP, 40-jts of 3.5" tbg, tail @ 1263'-SWI. Secure well and rig.
12/19/2016	Safety meeting. (windy conditions). Serivce rig and equipment. Field pressue 1291-psi-Windy conditions, 35-mph, Stand by. Shut down due to windy conditions 41-mph.
12/20/2016	Safety meeting. (slips,trips,falls). Serivce rig and equipment. Field pressue 1290-psi-Continue RIH w/ 193-jts of 3.5" tbg-P/U 1-jt w/ king swivel, tag TOL @ 7278'. Pull up 10' and set RBP 7268'-Test casing to 500-psi and it leaks off to 0 @ 7268'. Release RBP, Pull up and unable to set @ 7215'. Go back and tag LT @ 7278'. Set again @ 7268'. Release and set @ 7218'. Test casing and it leaks again at the same rate 500 to 0 psi in a couple of minutes. Release RBP and L/D king swivel-POOH w/ 116-jts of 3.5" tbg, tail @ 4861'-SWI. Secure well and rig.

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HISTORY OF OIL OR GAS WELL

Operator Southern California Gas Company Field Aliso Canyon County Los Angeles

Well Ward 3 A Sec. 27, T3N, R16W, S.B. B&M

A.P.I. No. 03722306 Name Tom McMahon (Person submitting report) Title SIMP Manager (President, Secretary, or Agent)

Date 4/27/2017 (Month, day, year)

Signature

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Start Date	Ops this Report (DOGGR)
12/21/2016	Safety meeting. (crane and lifting equipment). Serivce rig and equipment. Field pressue 1292-psi-POOH w/ 116-jts of 3.5" tbg, 8' pup jt, retrieving tool and RBP. Unloader was stuck open. Load out RBP onto truck-RIH w/ 8-5/8" RBP, 8' pup jt, 190-jts of 3.5" tbg. Stacking out @ 5900'. Work RBP free and drag up the hole 10' T/ 5890'. Tried 2 times and same results-R/U pump and hoses. Spot 64-bbls high vis pill. R/D hose and pour boy swivel-Pooh w/ 150-jts of 3.5" tbg, RBP @ 1263'-SWI. Secure well and rig.
12/22/2016	Safety meeting. (heat/cold stress). Serivce rig and equipment. Field pressue 1292-psi-Windy conditions, 35-mph +, Stand by-POOH w/ 40-jts 3.5" tbg, 8' pup and Baker 8-5/8" RBP. Brake down and load onto truck-RIH w/ bull nose and (2) 7.6" string mills, 8' pup jt PH/6, X/O, 190-jts of 3.5" tbg, tag @ 5887'. L/D 1-jt of 3.5" tbg-N/U flange and circulating head. Spot power swivel. R/U Power swivel. P/U 1-jt of 3.5" tbg-Begin milling F/ 5885' T/ 5892'. Pull mill up T/ 5883'-Circulate 2x bg volume @ 5883'- SWI. Secure well and rig.
12/27/2016	Safety meeting. (vehicle or heavy equipment). Serivce rig and equipment. Field pressue 1294-psi-Spot 80-bbls high vis pill down tbg-Stand by 35-mph + winds. Shit down due to 35-mph + winds.
12/28/2016	Safety meeting. (overhead utilities). Serivce rig and equipment. Field pressue 1294-psi-R/D power swivel, N/D flange and PGSR. L/D 2-jts of 3.5" tbg-POOH w/ 188-jts of 3.5" tbg, L/D string mill assembly-RIH w/ 7.6" single string mill, X/O, 8' pup jt PH/6, 190-jts of 3.5" tbg, tag @ 5887'. L/D 1-jt of 3.5" tbg-N/U flange and circulating head. R/U Power swivel. P/U 1-jt of 3.5" tbg and make connection-Begin milling F/ 5892' T/ 5909'. Pull up T/ 5883'.-Circulate 2x tbg volume @ 5883'-SWI. Secure well and rig.
12/29/2016	Safety meeting. (underground utilities). Serivce rig and equipment. Field pressue 1295-psi-Continue milling F/ 5909' T/ 5917', fell thru @ 5917' and slide down T/ 5945'-Reverse 2x tbg volume @ 5945'-R/D power swivel, N/D flange and PGSR. L/D 1-jts of 3.5" tbg-Continue RIH slow w/ 12-jts of 3.5" tbg, stack out @ 6287'-POOH w/ 162-jts of 3.5" tbg, tail @ 1262'-SWI. Secure well and rig.
12/30/2016	Safety meeting. (slips,trips,falls). Serivce rig and equipment. Field pressue 1294-psi-POOH / 40-jts of 3.5" tbg, 8' pup jt, L/D string mill-Off load tools from trailer w/ crane. Tally and picture tools-RIH w/ 7.57" string mill, 3.5" jars, (2) jts of 3.5" HWDP, X/O, 8' pup jt PH/6, 196-jts of 3.5" tbg, tag @ 6116'. Pull 2-jts, tail @ 6110'-SWI. Secure well and rig.
1/3/2017	Safety meeting. (crane and lifting equipment). Serivce rig and equipment. Field pressue 1296-psi-POOH w/ 184-jts of 3.5" tbg. Change of plans-RIH w/ 186-jts of 3.5" tbg, tag @ 6116'. Stand back 2-jt-N/U flange and circulating head. R/U Power swivel. P/U 1-jt of 3.5" tbg-Begin milling F/ 6116' T/ 6118' fell thru T/ 6145'. Circulate 1x tbg volume @ 6145'-R/D power swivel, L/D 1-jt of 3.5" tbg-Continue RIH w/ 10-jts 3.5" tbg, tag @ 6375'. Stand back 2-jts-R/U Power swivel. P/U 1-jt of 3.5" tbg-Begin milling F/ 6375' T/ 6377'. Circulate 2x tbg volume @ 6377'. Tail @ 6372'-SWI. Secure well and rig.
1/4/2017	Safety meeting. (heat/cold stress). Serivce rig and equipment. Field pressue 1296-psi-Continue milling F/ 6377' T/ 6382' fell thru @ 6382' T/ 6394'. Circulate 1x tbg volume-R/D power swivel, L/D 1-jt of 3.5" tbg-Continue RIH w/ 30-jts 3.5" tbg, tag TOL @ 7278'. R/U king swivel.Pull up 2' T/ 7276'-Reverse Circulate 2x tbg volume @ 7276'-L/D king swivel and 2-jts of 3.5" tbg. N/D flange and PGSR- POOH w/ 230-jts of 3.5" tbg, L/D 8' pup, X/O, (2) jts of 3.5" HWDP, 3.5" jars, 7.57 string mill-Unload sracper from trailer.RIH w/ 8-5/8" scraper, bumper sub, X/O, 8' PH/6 pup jt,72-jts of 3.5" tbg, tail @ 2557'-SWI. Secure well and rig.
1/5/2017	Safety meeting. (fire hazard). Serivce rig and equipment. Field pressue 1290-psi-Continue RIH w/ 162-jts of 3.5", tag TOL @ 7278'-R/U king swivel. Tag and Pull up 2' T/ 7276'. Reverse Circulate 2x tbg volume @ 7276'. L/D king swivel and 2-jts of 3.5" tbg-POOH w/ 192-jts of 3.5" tbg, tail @ 1264'. SWI- R/O power swivel and move off locaton. N/U shooting flange on X/O spool. Help crane load Baker tools and mills -Secure well and rig.
1/6/2017	Safety meeting. (wireline logging). Serivce rig and equipment. Field pressue 1290-psi-POOH w/ 40-jt kill string, L/D 8-5/8" scraper assembly-N/U X/O spool w/ shooting flange. R/U Schlumberger CBL tools w/ lubricator. Log well F/ surface T/ 7278'. Log well F/ 7278' T/ surface. R/D SLB wireline. N/D spool-RIH w/ 5.5' scraper, BS, 2-jts of 2-7/8" tbg, X/O, 40-jts of 3.5" tbg, tail @ 1320'-SWI. Secure well and rig.
1/9/2017	Safety meeting. (working w/ chemicals) Serivce rig and equipment. Field pressue 1294-psi-Continue RIH w/ 194-jts of 3.5" to 7339'. Make sevrel paases w/ scraper F/ 7280' T/ 7339'-R/U pourboy swivel. Reverse Circulate 2x tbg volume @ 7339'. L/D swivel-POOH w/ 196-jts of 3.5" tbg, tail @ 1258'-Secure well and rig.
1/10/2017	Safety meeting. (heat/cold stress). Serivce rig and equipment. Field pressue 1297-psi-POOH w/ 40-jt kill string, X/O, 2-jts 2-7/8" tbg, 5.5" srcaper assembly-N/U spool w/ shooting flange-R/U Western wireline w/ full lubricator. RIH w/ 60-arm caliper tool. Caliper liner F/ 7386' T/ 7278'-Off load 2-pallets of sand from Halliburton truck. Tally and move 4-jts of 2-7/8 tbg to trailer-RIH w/ 6-jts of 2-7/8" tbg, X/O, 232-jts of 35" tbg, tail @ 7393'-Secure well and rig.
1/11/2017	Safety meeting. (vehicle/heavy equiment). Serivce rig and equipment. Field pressue 1297-psi-Spot in crane off load Baker totes and pallet of sand from Halliburton truck. Lift 30 cu ft of 20/40 sand with crane to rig floor. Empty 30 bags of 60 mesh sand into 2-tote-Dump 30 cu ft of 20/40 sand down tubing while trickling water-R/U king swivel and hose. Move pipe up and down 30' while pumping .5-bpm down tbg. R/D king swivel and hose-POOH w/ 40-jts of 3.5' tbg, tail @ 6150'-Secure well and rig.
1/12/2017	Safety meeting. (overhead utilities). Serivce rig and equipment. Field pressue 1297-psi-RIH w/ 41 jts of .5" tbg, tag sand @ 7398'. POOH w/ 7-jts of 3.5" tbg, tail @ 7206'- R/U crane. Hold sand tote over well and Dump 30 cu ft of 60 mess sand down tubing while trickling water-R/U poorboy and hose. Displace tbg w/ 50-bbls polymer. R/D poorboy and hose-POOH w/ 40-jts of 3.5' tbg, tail @ 5964'-Secure well and rig-Change shaker screen F/ #16 T/ #20.

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DEPARTMENT OF CONSERVATION
DIVISION OF OIL, GAS, AND GEOTHERMAL RESOURCES

HISTORY OF OIL OR GAS WELL

Operator Southern California Gas Company Field Aliso Canyon County Los Angeles

Well Ward 3 A Sec. 27, T3N, R16W, S.B. B&M

A.P.I. No. 03722306 Name Tom McMahon (Person submitting report) Title SIMP Manager (President, Secretary, or Agent)

Date 4/27/2017 (Month, day, year)

Signature

Address PO Box 2300, SC9365, Chatsworth, CA 91313-2300 Telephone Number 714-398-5020

History must be complete in all detail. Use this form to report all operations during drilling and testing of the well or during redrilling or altering the casing, plugging, or abandonment, with the dates thereof. Include such items as hole size, formation test details, amounts of cement used, top and bottom of plugs, perforation details, sidetracked junk, bailing tests, and initial production data.

Start Date	Ops this Report (DOGGR)
1/13/2017	Safety meeting. (underground utilities). Serivce rig and equipment. Field pressue 1298-psi-RIH w/ 43 jts of 3.5" tbg, tag sand @ 7282'. POOH w/ 3-jts of 3.5" tbg, tail @ 7206'-Dump 6 cu ft of # 30 sand down tubing while trickling water-R/U poorboy and hose. Displace tbg w/ 50-bbls polymer. R/D poorboy and hose-POOH w/ 20-jts of 3.5' tbg, tail @ 6584'-Wait on sand to settle-RIH w/ 22-jts of 3.5" tbg, tag top of sand @ 7252', circulate down to 7264', reverse 2x tbg volume , tag top of sand @ 7264'-POOH w/ 140-jts 3.5" tbg, tail @ 2925'-Secure well and rig.
1/17/2017	Safety meeting. (crane / lifting equipment). Serivce rig and equipment. Field pressue 1299-psi-POOH w/ 88-jts of 3.5" tbg, X/O, L/D 6-jts of 2-7/8" tbg-RIH w/ 8-5/8" Baker RBP, retrieving tool, 8' pup jt, 83-jts of tbg, R/U king swivel. Set COE @ 2585'-Pull 3-jts of 3.5" tbg. Fill casing and tbg. Test casing T/ 600-psi. No test its leaking 100-psi in 15-minutes. Tryied 3-times same results. Rih w/ 3-jts, release RBP and reset @ 2570'. Pull 3-jts of 3.5" tbg. Test casing T/ 550-psi. No test its leaking 100-psi in 15-minutes. Tryied 2-times same results.POOH w/ 80-jts of 3.5" tbg, 8' pup jt, retrieving tool-RIH w/ 8-5/8" EA retrievamatic Baker packer, X/O, 8' pup jt, 81-jts of 3.5" tbg, set @ 2530'-Test RBP @ 2570' T/ 600-psi, bled down to 200-psi in 3-minutes. Chart Test casing F/ 2530' T/ surface T/ 600-psi for 15-minutes, good test-R/D testing equipment. Release packer. POOH w/ 45-jts of 3.5' tbg, tail @ 1140'-Secure well and rig.
1/18/2017	Safety meeting. (fire hazard). Serivce rig and equipment. Field pressue 1299-psi-POOH w/ 36-jt kill string, x/o, 8' pup jt, L/D packer on trailer-RIH w/ retriving tool, 8' pup jt, x/o, 83-jts of 3.5" tbg-R/U king swivel and hose. Ingauge RBP @ 2570', let equalize for 30-minutes. Release RBP and let rubbers set for 30-minutes. R/O king swivel and hose-POOH w/ 83-jts of 3.5" tbg, 8' pup jt, retrieving toolw/ 8-5/8" RBP. L/D plug-RIH w/ 8-5/8" Baker RBP, retrieving tool, 8' pup jt, 83-jts of tbg, R/U king swivel. Set COE @ 2593'-Pull 3-jts of 3.5" tbg, tail @ 2503'. Chart test RBP & casing T/ 600-psi for 15-minutes, good test- Dump 8 cu ft of sand down tubing while trickling water.Estamated Top of sand @ 2568'.R/U poorboy and hose.Displace tbg w/ 17.5-bbls polymer.R/D poorboy and hose-POOH w/ 80-jts of 3.5" tbg, 8' pup jt, retrieving tool-Clear floor of tools and equiment.R/D work floor and stairs. Spot crane,N/d HYD bag and remove-Secure well and rig.
1/19/2017	Safety meeting. (slips,tips,falls). Serivce rig and equipment. Field pressue 1301-psi-N/D BOP and rmove w/ crane. Get Hot work permit. Cut DSA bolts off well. Pull tbg spool and DSA off and load on cameron truck-N/U X/O spools and 5k double gate BOP. M/u 3" and 2" coflex hoses. R/U working floor-Chart test BOP to 500-psi for 15-minutes, good test. Swi-Spot weatherford pipe wrangler and pipe racks on tight location-Off load 44-jts of 6-5/8" casing w/ crane and tally-Secure rig.
1/20/2017	Safety meeting. (crane / lifting equipment). Serivce rig and equipment. Field pressue 1310-psi-Off load 143-jts of 6-5/8" casing w/ crane and tally total of 187 joints-Secure location-pump pit down to safe level.
1/23/2017	Safety meeting. (pinch points). Serivce rig and equipment. Field pressue 1301-psi-Empty cellar with cellar pump. N/D BOP, N/U X/O spools-Land DSA and tbg spool. N/U w/ cameron hyd wrenchs. Test DSA T/ 250-psi low and 3000-psi high, test tbg spool 250-psi low and 3200-psi high. R/D cameron-N/U BOP and bag, N/U coflex hoses. R/U floor and stairs-Install test hanger and 3.5" pu jt. Test piep rams 250-psi low and 5000-psi high. Test bag 250 low and 3500 high. Note: Cliff Knight w/ Doggr witnessed and approved BOP testing. R/D Weatherford-R/U tbg equipment. RIH w/ retrieving tool, 8' pup jt, x/o, 80-jts of 3.5" tbg, tail @ 2504'-Secure well and rig.
1/24/2017	Safety meeting. (work w/ chemicals). Serivce rig and equipment. Field pressue 1302-psi-N/U X/O and PGSR. RIH w/ 3-jts 3.5" tbg, install king swivel. Tag sand @ 2574'. C/O sand F/ 2574' T 2593'. Reverse 2xtbg volume. Release RBP. L/D king swivel. N/D X/O and PGSR-POOH w/ 83-jts of 3.5" tbg, x/o, 8' pup, retrieving tool w/ RBP. L/D Baker RBP on trailer-N/U x/o and shooting flange. R/U Western wireline w/ full lubricator. RIH w/ 8-5/8" Baker CIBP, set COE @ 2590'. POOH w/ wireline. R/D western. N/D x/o and shooting flange-RIH w/ 3.5" collar, x/o, 84-jts of 3.5" tbg, tag CIBP @ 2595',tbg measurements. Pull 4-jts, tail @ 2492'-Dump 6.5 cu ft of sand down tubing while trickling water. Estamated Top of sand @ 2575'. R/U poorboy and hose. Displace tbg w/ 17.5-bbls polymer. R/D poorboy and hose-Weight on sand to fall-RIH w/ 5-jts of 3.5" tbg, tag Top of sand @ 2575'-POOH w/ 83-jts of 3.5" tbg, x/o, collar-Secure well and rig.
1/25/2017	Safety meeting. (heat/cold stress). Serivce rig and equipment. Field pressue 1302-psi-N/U x/o and shooting flange. R/U Western wireline w/ full lubricator. RIH w/ 4" x 20' perf gun, tag sand @ 2570'. Perf F/ 2550' T/ 2530', 180° phasing, 2-spf, .40" holes. POOH w/ wireline-Open 13-3/8" casing, Chart Test 8-5/8" casing T/ 700-psi for 15-minutes and in bled down 50-psi in 15-minutes. No communication between 8-5/8" and 13-3/8" . Take chart to office-R/D Western wireline. n/d shooting flange and x/o. load all equipment on trailer-RIH w/ 3.5" collar, x/o, 40-jts of 3.5" tbg, tail @ 1251'-Empty cellar with cellar pump. Help gas company rep sniff gas from 13-3/8" gas and take water samples. Unable to get gas sample all water coming out. Load RBP, retieving tool and #4 setting tool in Baker trailer-Secure well and rig.
1/27/2017	Safety meeting. (vehicle/heavy equipment). Serivce rig and equipment. Field pressue 1302-psi-POOH w/ 40-jt kill string, x/o, 3.5" collar-N/U x/o and shooting flange. R/U Western wireline w/ full lubricator. RIH w/ 4" x 20' perf gun, Perf F/ 2530' T/ 2510', 180° phasing, 2-spf, .40" holes. POOH w/ wireline-Open 13-3/8" casing, Chart Test 8-5/8" casing T/ 700-psi for 15-minutes and in bled down 50-psi in 15-minutes. No communication between 8-5/8" and 13-3/8" . Take chart to office-R/D Western wireline. n/d shooting flange and x/o. load all equipment on trailer -Secure well and rig.
1/30/2017	Safety meeting. (overhead utilities). Serivce rig and equipment. Field pressue 1302-psi-N/U X/O and shooting flange. Spot truck. R/U Baker wireline. RIH w/ CBL, neutron, gama ray, log F/ 2570' T/ surface. R/D wireline-Empty cellar with cellar pump. Help gas company rep sniff gas and take sample of gas from 13-3/8" casing valve. Send sample to office-Secure well and rig.

Rec'd 05-04-17 DOGGR Ventura.

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1/31/2017	Safety meeting. (underground/Utilities). Serivce rig and equipment. Field pressue 1302-psi-N/U X/O and shooting flange. Spot Western wireline truck and unload lubricator & gun-R/U Western wireline w/ full lubricator. RIH w/ 4" x 5' perf gun, Perf F/ 2060' T/ 2055', 90° phasing, 4-spf, .43" holes. POOH w/ wireline-Pump down 8-5/8" casing taking returns in the 13-3/8", 3-bpm @ 150-psi. circulate 250-bbls-R/U Western wireline w/ full lubricator. RIH w/ 8-5/8" Baker CIBP, set COE @ 2000'. POOH w/ wireline. R/D western. N/D x/o and shooting flange. Test plug to 500-psi, good test-RIH w/ Baker CICR stab in tool, X/O, 64-jts of 3.5" tbg T/ 1999'-Remove striping plate. N/U X/O and circulating head. Space out tbg for cement job. Need 13' of pup jts in the moring-Secure well and rig.
2/1/2017	Safety meeting. (crane / lifting equipment). Serivce rig and equipment. Field pressue 1302-psi-space out well with 11' of pup jts. Stab into CICR. Put 500-psi on casing-R/U Halliburton cemeters. Test lines T/ 2500-psi. Pump and circulate out the13-3/8" casimg valve w/ 15-bbls fresh, 171-bbls of cmt (530 sacks), (960 cu ft) displace w/ 15.25-bbls polymer. SITP 500-psi-Pull out of CICR reverse circulate 30-bbls of polymer, send residuals into half bin. Switch valves and circulate down tbg 5-bpm, pumped 131-bbls total- R/D cement equipment. Pull 3' pup and 5' pup jts. N/D X/O and pgsr-POOH w/ 64-jts 3.5" tbg, x/o, Baker stab in. load stab in on trailer-Picture and caliper (4) 4-3/4" drill collars. P/U drill collars and stand back in derrick-Spot power swivel on containment. Have crane lift swivel to floor. Hang power swivel-Secure well and rig.
2/2/2017	Safety meeting. (fire hazard). Serivce rig and equipment. Field pressue 1302-psi-Off load Baker packer plicker, LBS, Jars. Picture and tally Baker tools-RIH w/ Baker packer plucker w/ junk baskets, (4) 4-3/5" DC, LBS, oil Jar, 58-jts of 3.5" tbg, tail @ 1975'-N/U flange and circulating head. R/U Power swivel. P/U 2-jt of 3.5" tbg. Tag CICR @ 2008'-Begin milling CICR F/ 2008' T/ 2010', its sliding down. Circulate 146-bbls-R/D swivel. L/D 2-jts of 3.5" tbg. N/D and remove X/O and PGSR-POOH w/ 58-jts of 3.5" tbg, X/O, (4) DC, jar, LBS, plucker assemble. CICR is not on plucker. Milled down ring was found in shoe-C/O to tbg equipment. Rih w/ 40-jts kill string, tail @ 1247'-Secure well and rig.
2/3/2017	Safety meeting. (slips,trips,falls). Serivce rig and equipment. Field pressue 1304-psi-POOH w/ 40-jt kill string-RIH w/ 5-7/8" short catch w/ 4-5/8" grapple, LBS, Jar, 4-DC, X/O, 59-jts of 3.5" tbg-R/U king swivel and P/U 1-jt, circulate down to fish @ 2012'. Latch fish and pull free. L/D king swivel-POOH w/ 60-jts of 3.5" tbg, x/o, 4-DC, jar, LBS, over shot w/ CICR. Load fishng tool into Baker truck-RIH w/ 7-3/8" rock bit w/ junk basket, (4) 4-3/5" DC, 60-jts of 3.5" tbg T/ 2006'-N/U flange and circulating head. R/U Power swivel. P/U 1-jt of 3.5" tbg. Tag TOC @ 2012'-Begin drilling cement F/ 2012' T/ 2057'. Circulate 3x tbg volume 30-bbls. Pull bit T/ 2035'-Secure well and rig.
2/6/2017	Safety meeting. (pinch points). Serivce rig and equipment. Field pressue 1305-psi- Continue drilling cement F/ 2057' T/ 2065', fell thru T/ 2069'. Circulate 2x tbg volume. R/D power swivel- Test casing T/ 500-psi with 13-3/8" casing open for 15-minutes. It leaked 100-psi in 15-minutes-RIH and stack out @ 2070'. L/D 6-jts 0f 3.5" tbg. RIH w/ 3-stands from derrick. R/U power swivel-C/O cement stringers F/ 2070' T/ 2162', slide down T/ 2256'. Circulate 2x tbg volume. Rack back swivel. RIH w/ tbg from derrick, tag sand @ 2575'. R/U swivel, Clean out sand F/ 2575' T / 2585'-R/D swivel. L/D 1-jts of 3.5" tbg. N/D and remove X/O and PGSR-POOH w/ 78-jts of 3.5" tbg, x/o, 4-DC, L/D junk basket, L/D bit sub, L/D 7-3/8" bit-Make up and RIH w/ 3.5" sawtooth, x/o, 8-5/8" srcaper, BS, (4) 4-3/5" DC, 60-jts of 3.5" tbg T/ 2002'-Secure well and rig.
2/7/2017	Safety meeting. (working w/ chemicals). Serivce rig and equipment. Field pressue 1300-psi-Continue RIH w/ tbg, tag sand @ 2585'. Reverse circulate F/ 2585' T /2595' 100-bbls. Pump strait ahead 150-bbls @ 5-bpm-L/D 1-jt of 3.5" tbg. POOH w/ 78-jts of 3.5" tbg, x/o, 4-DC, L/D BS, L/D 8-5/8" scraper, x/o, 3.5" sawtooth collar-RIH w/ Baker packer plucker w/ junk baskets, (4) 4-3/5" DC, LBS, oil Jar, 77-jts of 3.5" tbg, tail @ 2565'-N/U x/o flange and circulating head. R/U Power swivel. P/U 2-jt of 3.5" tbg. Tag CICR @ 2595'Begin milling CICR F/ 2595' T/ 2596', its sliding down. Circulate 150-bbls-R/D swivel. L/D 1-jt of 3.5" tbg. N/D and remove X/O and PGSR-POOH slow w/ 46-jts of 3.5" tbg, tail @ 1169'-Secure well and rig.
2/8/2017	Safety meeting. (hear/cold stress). Serivce rig and equipment. Field pressue 1305-psi-POOH slow w/ 32-jts of 3.5" tbg, X/O, (4) DC, L/D jar, L/D LBS, L/D plucker assemble w/ CICR on it-RIH w/ 3.5" sawtooth, x/o, 8-5/8" srcaper, BS, (4) 4-3/5" DC, 230-jts of 3.5" tbg, tag top of sand @ 7272'-POOH w/ 230-jts of 3.5" tbg, x/o, 4-DC, L/D BS, L/D 8-5/8" scraper, x/o, 3.5" sawtooth collar-RIH w/ 38-jt kill string, tail @ 1190'-Secure well and rig.
2/9/2017	Safety meeting. (vehicle/heavy equipment). Serivce rig and equipment. Field pressue 1305-psi-POOH w/ 38-jt kill string-Land hanger w/ pup jt. Change pipe rams T/ 6-5/8". Close bag and Test to 500-psi. no leaks-R/U Weatherford 6-5/8" casing equipment-RIH thread locking re-enrty collar, 1-jt of 6-5/8" casing w/ float, 1-jt of 6-5/8" casing, 1-jt of 6-5/8" casing w/ float, 3-jts of 6-5/8" casing, 20' pup, add tread lube on 45-jts of 6-5/8" casing, added centralizers on every jt of casing, tail @ 2240'. Up 45k, down 10k @ 1000'. @ 1500', 68k and 20k, @ 2000', 86k and 24k-Secure well and rig.
2/10/2017	Safety meeting. (overhead utilities). Serivce rig and equipment. Field pressue 1303-psi-Continue RIH w/ 63-jts of 6-5/8" casing installing centralizers on every jt of casing, tail @ 4810'. Up and down weights @ 2500', 104k and 28k, @ 3000', 131k and 31k, @ 3500', 160k and 34k, @ 4000', 190k and 40k, @ 4500', 220k and 44k-Secure well and rig.
2/13/2017	Safety meeting. (underground utilities). Serivce rig and equipment. Field pressue 1303-psi-Continue RIH w/ 57-jts of 6-5/8" 24# casing. Tail @ 7256'. Cameron on location and land casing on slips @ 150k- Spot crane and load 16-jts of 6-5/8" casing onto trailer. R/D Weatherford casing equipment. R/D Weatherford pipe wrangler and pipe racks-Pump 130-bbls of polymer down 6-5/8" casing, send returns to return tank. Switch valves and continue Circulating 236-bbls of fresh polymer. 366-bbls of fresh polymer circulated-Secure well and rig.

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2/14/2017	Safety meeting. (crane / lifting equipment). Serivce rig and equipment. Field pressue 1303-psi-Spot Halliburton on loaction. R/U pump truck, bulk truck, water truck. Install cement head. Test lines T/ 4500k-high. Pump 10-bbls fresh w/ green dye, 10-bbls spacer-76 bbls/230 sacks of 13 5# of lead cmt & 36 bbls/110 sacks of 14.8 tail, drop wiper plug and displace w/ 245-bbls polymer did not bump plug-final circulating pressure 2800 @ 2 bbls/min. had 5 bbls of green dye fresh water back at surface.Cip @ 9:30am. R/D Halliburton.***EST. TOP OF CEMENT @ 900'***-R/D stairs and floor. Install 4-way sling on BOP. N/D BOP and lift off flange. Cameron on location and pack off casing slips. N/U BOP and test slips to 500-psi, good test.Secure well and rig.
2/21/2017	Safety meeting. (fire hazard). Serivce rig and equipment. Field pressue 1303-psi-Spot crane. Off load DSA and tbg spool from cameron truck. N/D Bag, co-flex hoses, Double gate-Spot Cameron on location. Cut 6-5/8' casing. N/U DSA and tbg spoool. Test DSA 250-low ans 4600-high. Test tbg spool 250-low and 4600-high. R/D Cameron-N/U crossover spool, double gate, land bag. Shut blind rams-Secure well and rig.
2/22/2017	Safety meeting. (slips,trips,falls). Serivce rig and equipment. Field pressue 1303-psi-Continue N/U bag, co-flex hoses. R/U floor extentions and strairs-Land hanger w/ 3.5" pup jt. Remove check valve. Test bag T/ 300-L and 3500-H. Test pipe rams, 2" valves, 3" valves, co-flex hoses, choke maifold T/ 300-L and 5k-H. remove pup jt and install check valve. Test blind rams 300-L and 5k-H. R/D Weatherford tester***BOP inspection done by Miguel Oziedo with DOGGR***L/D (4) 4-3/4" drill collars. Bring all 4-3/4" equipment off floor-Picture and tally drilling BHA. RIH w/ 5.75" bit, BS, (4) 4.25" DC, X/O, tally 100-jts of 3.5" PH/6 tbg from derrick, tail @ 3225'-Secure well and rig.
2/23/2017	Safety meeting. (pinch points). Serivce rig and equipment. Field pressue 1306-psi-Continue RIH strapping 126-jts of PH/6 tbg from derrick, tag TOC @ 7123'. L/D 8-jts from derrick-N/U x/o flange and circulating head. R/U Power swivel. P/U 2-jt of 3.5" tbg. Tag TOC @ 7123'-Begin C/O wiper plug and cement F/ 7123' T/ 7165'. Drill out float and cement F/ 7165' T 7180'. Reverse Circulate 3x tbg volume. Pull bit up T/ 7160'-Secure well and rig.
2/24/2017	Safety meeting. (working w/chemicals). Serivce rig and equipment. Field pressue 1306-psi-Continue C/O cement F/ 7180' T / 7224', reverse 2x tbg volume @ 7224'-R/D swivel. L/D 1-jt of 3.5" tbg. N/D and remove X/O and PGSR-POOH w/ 228-jts of 3.5" tbg, x/o, 4-DC, bit sub @ 5.75" bit. Close blind rams and test casing to 1000 -psi, good test- Picture and tally scraper BHA. RIH w/ 6.625" scraper, BS, (4) 4.25" DC, X/O, 229-jts of 3.5" PH/6 tbg, tag @ 7224'-Reverse circulate 2x tbg volume @ 7224'-L/D 1-jt of 3.5" tbg. POOH w/ 114-jts of 3.5" tbg, tail @ 3661'-Secure well and rig.
2/27/2017	Safety meeting. (heat/cold stress). Serivce rig and equipment. Field pressue 1307-psi-POOH w/ 114-jts of 3.5" tbg, x/o, 4-DC, BS, scraper-N/U shooting flange. Spot truck. R/U Baker Hughes wireline. RIH w/ 56-arm caliper, tag @ 7224', log F/ 7224' T/ surface. First HRVT logging tool wouldnt go past well head. L/D tool and RIH w/ back up HRVT logging tool, log F/ surface T / 5700', unable to get past 5700'. Log F/ 5680' T/ surface. R/D wireline-Secure well and rig.
2/28/2017	Safety meeting. (heat/cold stress). Serivce rig and equipment. Field pressue 1310-psi-Spot Schlumberger wireline. R/U SLB. RIH w/ USIT logging tool, Log F/ surface T/ 7220'. Log F/ 7220' T/ surface. R/D SLB wireline- RIH w/ test packer-Secure well and rig.
3/1/2017	Safety meeting. (overhead utilities). Serivce rig and equipment. Field pressue 1309 -psi-Continue RIH w/ test packer, set Halliburton test packer COE @ 4000'-R/U PROS tester. Ernie Blevins w/ DOGGR witnessed and approved pressure integrity test of 6-5/8" 24# casing F/ 7223' T/ surface for 1-hour F/ 9am T/10am, F/ 2348-psi bled T/ 2338-psi. Ernie Blevins w/ DOGGR witnessed and approved pressure integrity test of 6-5/8" 24# casing F/ 4000' T/ surface for 1-hour F/ 10:40am T/ 11:40am, F/ 3789-psi bled T/ 3774-psi. R/D Pros tester-Release Halliburton packer, wait 30-minuites for packer to relax. L/D 1-jt of 3.5" tbg. POOH w/ 128-jts of 3.5" tbg, x/o, test packer. Load packer into Halliburton truck-RIH w/ 5.75" bit, BS, (4) 4.25" DC, X/O, 156 -jts of 3.5" PH/6 tbg from derrick, tail @ 4962'-Secure well and rig.
3/2/2017	Safety meeting. (underground utilities). Serivce rig and equipment. Field pressue 1309-psi-Continue RIH w/ 73-jts of 3.5" tbg, T/ 7220'-N/U x/o flange and circulating head. R/U Power swivel. P/U 1-jt of 3.5" tbg. Tag TOC @ 7223'-Begin C/O cement and float collar F/ 7223' T/ 7256', C/O cement strings F/ 7256' T/ 7267. Circulate well clean @ 7267'-R/D swivel. N/D and remove X/O and PGSR-POOH L/D 15-jts of 3.5" tbg and stand back 108-js of 3.5" tbg, tail @ 3470'-Secure well and rig.
3/3/2017	Safety meeting. (crane / lifting equipment). Serivce rig and equipment. Field pressue 1310-psi-Continue POOH w/ 108-js of 3.5" tbg, x/o, 4-DC, x/o, 5.75" bit. R/D 4.25" tbg equipment-R/U 2-3/8" tbg equipment. RIH w/ 4.75" bit, BS, P/U 15-jts of 2-3/8" PH/6, x/o, 219-jts 0f 3.5" tbg, T/ 7256'-N/U x/o flange and circulating head. R/U Power swivel. P/U 1-jt of 3.5" tbg. Tag @ 7267'-Begin C/O F/ 7267' T/ 7281', power swivel broke down. Call weattherford for repairs. Circulate well clean @ 7281'. Pull bit up T/ 7257'-Secure well and rig.
3/6/2017	Safety meeting. (Slips trips & fallst). Serivce rig and equipment. Field pressue 1310-psi-Continue C/O F/ 7281' T/ 7321', circulate well clean @ 7321'-R/D swivel. N/D and remove X/O and PGSR. L/D 2-jts of 3.5" tbg-POOH w/ 220-jts of 3.5" tbg, x/o, 15-jts of 2-3/8" tbg, BS, 4.75' bit. Note: 3-roller cones missing-RIH w/ 38-jt kill string, tail @ 1177'-Secure well and rig.
3/7/2017	Safety meeting. (fire/hazard). Serivce rig and equipment. Field pressue 1310-psi-POOH w/ 38-jts of 3.5" tbg-Unload 6-Drill collars and tool basket-Picture, caliper tools. RIH w/ 4.75" junk basket, x/o, (6) 3-1/8" DC, x/o, 14-jts of 2-3/8" PH/6 tbg, x/o, 216-jts of 3.5" tbg-N/U x/o flange and circulating head. R/U Power swivel. P/U 1-jt of 3.5" tbg. Tag @ 7321'-Begin circulating with junk basket F/ 7321' T/ 7321'-R/D swivel. N/D and remove X/O and PGSR. L/D 1-jts of 3.5" tbg-POOH w/ 100-jts of 3.5" tbg, tail @ 4335'-Secure well and rig.

Rec'd 05-04-17 DOGGR Ventura.

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION
DIVISION OF OIL, GAS, AND GEOTHERMAL RESOURCES

HISTORY OF OIL OR GAS WELL

Operator Southern California Gas Company Field Aliso Canyon County Los Angeles

Well Ward 3 A Sec. 27, T3N, R16W, S.B. B&M

A.P.I. No. 03722306 Name Tom McMahon (Person submitting report) Title SIMP Manager (President, Secretary, or Agent)

Date 4/27/2017 (Month, day, year)

Signature

Address PO Box 2300, SC9365, Chatsworth, CA 91313-2300 Telephone Number 714-398-5020

History must be complete in all detail. Use this form to report all operations during drilling and testing of the well or during redrilling or altering the casing, plugging, or abandonment, with the dates thereof. Include such items as hole size, formation test details, amounts of cement used, top and bottom of plugs, perforation details, sidetracked junk, bailing tests, and initial production data.

Start Date	Ops this Report (DOGGR)
3/8/2017	Safety meeting. (slips,trips,falls). Serivce rig and equipment. Field pressue 1312-psi-Safety meeting. (slips,trips,falls). Serivce rig and equipment. Field pressue 1312-psi-POOH w/ 120-jts 3.5" tbg, 14-jts of 2-3/8" tbg, (6) DC's and junk basket. Note: found 1-cone, cement pieces and small slip pieses from CICR-L/D (6) 3-1/8" drill collars due to flared connections-RIH w/ 4.5" junk basket, x/o, 14-jts of 2-3/8" PH/6 tbg, x/o, 221-jts of 3.5" tbg-N/U x/o flange and circulating head. R/U Power swivel. P/U 1-jt of 3.5" tbg. Tag @ 7321'-Begin circulating with junk basket F/ 7321' T/ 7322'-R/D swivel. N/D and remove X/O and PGSR. L/D 2-jts of 3.5" tbg-POOH w/ 50-jts of 3.5" tbg, tail @ 5710'-Secure well and rig.
3/9/2017	Safety meeting. (pinch points). Serivce rig and equipment. Field pressue 1310-psi-POOH w/ 170-jts 3.5" tbg, 14-jts of 2-3/8" tbg, junk basket. Note: found 2-cones and 1-shaft-Unload 6 serviced 3-1/8" Drill collars and tool basket from trailer. Load 6-used drill collars and tool basket on trailer-Stand by on tools from Weatherford. Clean location, greese rig and tongs while waiting-Caliper and measure shu. RIH w/ 4" sawtooth shu basket, 14-jts 2-3/8", 148-jts of 3.5" tbg, tail @ 5030'- Secure well and rig.
3/10/2017	Safety meeting. (working w/ chemicals). Serivce rig and equipment. Field pressue 1310-psi-RIH w/ 73-jts of 3.5" tbg T/ 7294'-N/U x/o flange and circulating head. R/U Power swivel. P/U 1-jt of 3.5" tbg. Tag @ 7322'-Begin circulating with junk basket F/ 7322' T/ 7323'-R/D swivel. N/D and remove X/O and PGSR. L/D 2-jts of 3.5" tbg-POOH w/ 220-jts of wet 3.5" tbg, 14-jts of 2-3/8", 4" sawtooth finger basket. Note: found pluged x/o's, pluged with metal and some sand-RIH w/ 4.75" bit, (6) 3-1/8" collars, 14-jts of 2-3/8" PH/6, 30-jts of 3.5" tbg, tail @ 1550'-Secure well and rig.
3/13/2017	Safety meeting. (heat/cold stress). Serivce rig and equipment. Field pressure 1260-psi-RIH w/ 186-jts of 3.5" tbg T/ 7309'-N/U x/o flange and circulating head. R/U Power swivel. P/U 1-jt of 3.5" tbg. Tag @ 7324'-C/O cement F/ 7324' T/ 7376'. Circulate well clean @ 7376'-R/D swivel. N/D and remove X/O and PGSR. L/D 1-jt of 3.5" tbg-POOH w/ 36-jts of 3.5" tbg, tail @ 6255'-Secure well and rig.
3/14/2017	Safety meeting. (vehicle/heavy equipmentt). Serivce rig and equipment. Field pressue 1260-psi-POOH w/ 182-jts of 3.5" tbg, 14-jts of 2-3/8", (6) 3-1/8" DC, BS, 4.75" bit in fair condition-RIH w/ 4.75" sealed bearing bit, (6) 3-1/8" collars, 14-jts of 2-3/8" PH/6, 218-jts of 3.5" tbg T/ 7371'-N/U x/o flange and circulating head. R/U Power swivel. P/U 1-jt of 3.5" tbg. Tag @ 7376'-C/O F/ 7376' T/ 7383'. Circulate well clean @ 7383'-R/D swivel. POOH w/ 5-jts of 3.5" tbg, tail @ 7246'-Secure well and rig.
3/15/2017	Safety meeting. (overhead utilities). Serivce rig and equipment. Field pressue 1311-psi-'-RIH w/ 4-jts of .5" tbg. R/U swivel and p/u 1-jt, tag @ 7383'-C/O F/ 7383' T/ 7437". Circulate well clean @ 7435". Note: drill break F/ 7402' T 7408' R/D swivel. POOH to above liner top @ 7246'-Secure well and rig.
3/16/2017	Safety meeting. (underground utilities). Serivce rig and equipment. Field pressue 1312-psi-RIH w/ 8-jts of .5" tbg. R/U swivel and p/u 1-jt, tag @ 7437'-C/O cement F/ 7437' T/ 7475'-Reverse circulate 3x tbg volume @ 7475'- R/D swivel. N/D and remove X/O and PGSR. L/D 2-jt of 3.5" tbg-POOH w/ 40-jts of 3.5" tbg, tail @ 6255'-Secure well and rig.
3/17/2017	Safety meeting. (crane / lifting equipment). Serivce rig and equipment. Field pressue 1312-psi-POOH w/ 180-jts of 3.5" tbg, 14-jts of 2-3/8", (6) 3 -1/8" DC, BS, 4.75" bit in fair condition. Inspect bit.-RIH w/ 4.75" sealed bearing bit w/ jets taken out, (6) 3-1/8" collars, 14-jts of 2-3/8" PH/6, 212 -jts of 3.5" tbg Tail @ 7185'-N/U x/o flange and circulating head. Tail @ 7185'-Secure well and rig.
3/20/2017	Safety meeting. (fire/hazard). Serivce rig and equipment. Field pressue 1311-psi-RIH w/ 8-jts of .5" tbg. R/U swivel and p/u 1-jt, tag @ 7475'-C/O cement F/ 7475' T/ 7485'. C/O sand F/ 7485' T/ 7658'-Reverse circulate 3x tbg volume @ 7658'-R/D swivel. L/D 2-jt of 3.5" tbg, N/D PGSR. POOH w/ 14-jts of 3.5" tbg, tail @ 7184'-Secure well and rig.
3/21/2017	Safety meeting. (slips,trips,falls). Serivce rig and equipment. Field pressue 1311-psi-POOH w/ 212-jts of 3.5" tbg, 14-jts of 2-3/8", L/D (6) 3-1/8" DC, BS, 4.75" bit in good condition-L/D (4) 4.75" drill collars. Clear floor of all 3-1/8" and 4-3/4" drill collar equipment, load into baskets. Use crane to load out power swivel. Spot tbg racks for L/D pipe-Picture and tally scraper BHA. RIH w/ 5.5" scraper, BS, X/O, 14-jts of 2-3/8" PH/6, 216-jts of 3.5" PH/6 tbg, tag @ 7175'-Secure well and rig.
3/22/2017	Safety meeting. (pinch points). Serivce rig and equipment. Field pressue 1312-psi-RIH w/ 16-jts of 3.5" tbg, tag @ 7648' (10' high)-Reverse circulate fill out F/ 7648' T/ 7658'. Change hole over w/ 300-bbls of fresh polymer-POOH L/D 210-jts of 3.5" PH/6 tbg adding thread protectors on each end, tail @ 1165'- Unload Hydril 563 3.5" production tbg from 1st trailer. Spot thread protector baskets and x/o's-Secure well and rig.
3/23/2017	Safety meeting. (crane / lifting equipment). Serivce rig and equipment. Field pressue 1313-psi-Windy conditions 40-mph winds in derrick-Off load 2nd trailer w/ production tbg. Tally 240-jts of 3.5" 563-hyd tbg. Tally pup jts. Unload Halliburton packer and sleeve from trailer-Unload Weatherford tongs and elevators. Set up tongs and hoses. Function test and set torques-Spot vac truck and wash pump, catch bin and frac tank -Secure well and rig. Take trash to bins. Eot.
3/24/2017	Safety meeting. (Running completiont). Serivce rig and equipment. Field pressue 1313-psi-POOH L/D 22-jts of 3.5" tbg, 15-jts of 2-3/8" tbg, BS, 5.5" scraper w/ 4.75" bit-Change over to 3.5" tbg equipment. Set up tbg tong computer system. Western wireline on ,location and load plug into XN-nipple. X/N nipple 2.813" w/ 2.75" no-go- RIH 3.5" re-entry collar, XN-Nipple (2.75") loaded w/ Western wireline plug, pup jt, 6-5/8" ASI retrievable packer, pup jt, 1-jt of 3.5" L-80 9.3# 563-HYD, pup jt, Sliding sleeve, 1-jt of 3.5" L-80 9.3# 563-HYD. R/U tester and unable to get test. R/U wireline and unable to find plug at 104', went to 200'. plug is gone. R/D wireline. decision was made to keep running pipe to kill string depth and will bundle test when plug is here on Monday-Continune RIH w/ 48-jts of 3.5" L-80 9.3# 563-HYD, tail @ 1619'-Secure wel.

Rec'd 05-04-17 DOGGR Ventura.

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION
DIVISION OF OIL, GAS, AND GEOTHERMAL RESOURCES

HISTORY OF OIL OR GAS WELL

Operator Southern California Gas Company Field Aliso Canyon County Los Angeles

Well Ward 3 A Sec. 27, T3N, R16W, S.B. B&M

A.P.I. No. 03722306 Name Tom McMahon (Person submitting report) Title SIMP Manager (President, Secretary, or Agent)

Date 4/27/2017 (Month, day, year)

Signature

Address PO Box 2300, SC9365, Chatsworth, CA 91313-2300 Telephone Number 714-398-5020

History must be complete in all detail. Use this form to report all operations during drilling and testing of the well or during redrilling or altering the casing, plugging, or abandonment, with the dates thereof. Include such items as hole size, formation test details, amounts of cement used, top and bottom of plugs, perforation details, sidetracked junk, bailing tests, and initial production data.

Start Date	Ops this Report (DOGGR)
3/27/2017	Safety meeting. (working w/ chemicals). Serivce rig and equipment. Field pressue 1314-psi-R/U Western wireline. RIH and set 2.805" plug in xn @ 1614'. Test w/ pros F/ 3756-psi T/ 3736-psi 20-psi drop in 30-minutes. RIH and pull plug F/ 6114'. R/D wireline-Continue RIH w/ 176-jts of 3.5" 9.3# 563-hyd, 10' pup, 4' pup jt, tbg hanger-R/U king swivel w/ 8' pup jt. Circulate 100-bbls of packer fluid down tbg out casing-Set packer COE @ 7150', up weight 84K, down weight 72K. Pull 30k over for 30-minutes. Land hanger,run lock screws.Test casing to 1000-psi for 15-minutes. R/D Weatherford tbg equipment-Secure well and rig.
3/28/2017	Safety meeting. (Heat/cold stress). Serivce rig and equipment. Field pressue 1313-psi-R/U Western wireline. RIH and set (2.813") PXN-plug body in plug @ 7165'. POOH. RIH w/ prong and set in body @ 7165'. POOH. R/D wireline-R/U PROS tester. Ernie Blevins w/ DOGGR witnessed and approved pressure integrity test of 3.5" tbg F/ 7165' T/ surface for 1-hour F/ 9:18am T/10:18am, F/ 3839-psi bled T/ 3836-psi. Ernie Blevins w/ DOGGR witnessed and approved pressure integrity test of 6-5/8" 24# casin and packer F/ 7150' T/ surface for 1-hour F/ 10:42am T/ 11:42am, F/ 1107-psi bled T/ 1106-psi. R/D Pros tester-RIH w/ wireline and shift sleeve open. POOH. R/D Western wireline-R/U Cameron. Set 2-way. R/D floor and stairs. N/D HYD bag, N/D BOP and co-flex hoses-N/U well head. Chart Test bonnet 300-low, 5000-high. Unable to test shell due to tree cap o-ring is bad. R/D cameron-Secure well and rig.
3/29/2017	Safety meeting. (vehicle/heavy equipment). Serivce rig and equipment. Field pressue 1313-psi-Install tree cap. Chart Test shell 300-low, 5000-high. Pull BPV. R/D cameron- Drop wires. RDMO. Load all equipment w/ crane onto trailers. Install guards around well-Remove guards on 32D, 32E, 32F and install 4-1" plates on each well 2" high total-spot plate rig up on. Roll out containment. Spot rig mat on containment-Road rig from Ward 3A to Porter 32C location. Spot rig on jacks-secure location.
4/17/2017	MIRU Premier N2 & Onyx flowback equipment. Pumped N2 through casing taking fluid returns f/ tbg. to tank via separator. Recovered 227 bbls. C.W.I. S.I.S.D.F.N.
4/18/2017	Closed sleeve. Applied pressure. Retrieved prong & plug. Flow tested well. Well went flat. C.W.I.

Ex. I – 55

Elevation: 1995' G.L.
KB: 12'
MV 8'

Observation Well

IW-60

13-3/8" -40# H-40
Cmt'd 505 SX

694'

8-5/8" -36# K55-N80
Cmt'd 600 SX

2-7/8" 6.5# N80 Tbg.

---7039'

---Top of cement 7053'

---7152'

Inr. 7283'

WSO 7285'

shoe 7359'

---S4 7390' (7154')

7416'

6-5/8" 28#
J-55 FJ liner

7454'

---S8 7475' (7232')

7476'

Perfs
4-1/2" per ft.

7550'

7559' -7565'

7580'

7582' TD

7666' (7407') (-5400')

9/12/72 - Well spud.
11/14/72 - Well completed.
7/26/77 - Well pulled and tubing replaced - run with downhole safety system.
7/27/82-8/12/82 - Plugged back and converted to an Observation Well. Plugged with cement from 7582'-7152'. Squeezed holes in casing at 7207'..7250', 7278'. Cut window from 7260'-7280' and squeezed with 10 cu. ft. cement. Ran tubing open-ended and located top of cement at 7053'.

Volume		Cu. Ft.	BBL
Tubing	-	229	40.7
Annulus	-	2038	362.9
Total	-	2267	403.6

5-30-85

Ex. I – 56

SUBMIT IN DUPLICATE

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION

DIVISION OF OIL AND GAS

History of Oil or Gas Well

Operator Southern California Gas Co. Field or County Aliso Canyon
Well I. W. #70, Sec. 29, T 3N, R 16W., SB B. & M.
A.P.I. No. 037-21375 Name P. S. Magruder, Jr. (Person submitting report) Title Agent (President, Secretary or Agent)
Date February 22, 1979, 19

Signature PSM/ O. S. [illegible]

P.O. Box 3249 Terminal Annex, Los Angeles, Ca. 90051 (Address) (213) 689-3561 (Telephone Number)

History must be complete in all detail. Use this form to report all operations during drilling and testing of the well or during redrilling or altering the casing, plugging, or abandonment with the dates thereof. Include such items as hole size, formation test details, amounts of cement used, top and bottom of plugs, perforation details, sidetracked junk, bailing tests and initial production data.

Date	
1978	Program: To pull tubing and 5" innerstring. Correct leak in 6 5/8" liner. Set packers in 6 5/8" and 8 5/8" casings and connect with blank tubing. Rerun safety system and return the well to gas storage operation.
12-15	0 Day. Killed well with 400 barrels of 80# brine-polymer completion fluid and began rigging up.
12-16	1st Day. Moved California Production Service Co. rig #D-6 onto wellsite and began rigging up.
12-17	Rig and crew idle.
12-18	2nd Day. Completed rig up. Circulated well. Installed back pressure valve in tubing hanger. Removed tree and installed BOPE.
12-19	3rd Day. Pressure tested blank rams, 2 7/8" pipe rams and choke manifold to 4,000 psi with water and nitrogen for 20 minutes - OK. Tested Hydril bag to 3,000 psi with water and nitrogen for 20 minutes. All tests were witnessed and approved by D.O.G. Released from Otis "Permatrieve" packer at 8,200'. Pulled up to 8,138'.
12-20	4th Day. Laid down 115 joints of 2 7/8" tubing and 121 joints of 2 3/8" tubing. Ran Otis retrieving tool on 2 7/8" drill pipe. Picked up 2,100' of 2 7/8" drill pipe.
12-21	5th Day. Continued picking up 2 7/8" drill pipe. Latched into Otis "Permatrieve" packer at 8,209'. Pulled packer loose - could not pull packer above 8,178'.
12-22	Rig and crew idle.
12-23	Rig and crew idle.

OG 103 (6-78-GSR1-10M)

History of Well Report for I.W. #70, Aliso Canyon

1978

12-24 Rig and crew idle.

12-25 Rig and crew idle.

12-26 6th Day. Retrieved Otis 5" "Permatrieve" packer. Ran 7 5/8" bit and 8 5/8" casing scraper on 2 7/8" drill pipe to 3,894'. Circulated and pulled out of well. Ran 5" inside cutter on 2 7/8" drill pipe and cut 5" casing at 3,916'. Started out of well with cutter.

12-27 7th Day. Pulled 5" cutter out of well. Ran 5" spear and attached to top liner hanger. Retrieved 8 5/8" x 5" liner hanger and 14' of casing. Ran 5" overshot and attached to 5" liner. Ran Free-point and found 5" innerstring free above 7,490'.

12-28 8th Day. Released overshot from 5" innerstring and pulled out of well. Ran 5" inside casing cutter to 7,315' and cut casing. Ran 5" overshot and attached 5" casing. Jarred innerstring loose (180,000#) and started out of well.

12-29 9th Day. Finished pulling out of well with overshot and recovered 5" innerstring from 3,916' to 7,315' (3,399'). Ran 5" spear in well and latched into 5" innerstring at 7,315'. Jarred and pulled 190,000# for one hour. Innerstring would not move. Released spear and started out of well.

12-30 10th Day. Finished pulling out of well with spear. Ran 5" cutter to 7,395' and cut 5" innerstring. Started in well with 5" spear.

12-31 Rig and crew idle.

1979

1-1 Rig and crew idle.

1-2 11th Day. Stood by with crew waiting for wind to subside.

1-3 12th Day. Attached 5" spear to innerstring. Pulled out of well. Recovered 80' of 5" casing from 7,315' to 7,395'. Ran 5" cutter to 7,555' and cut 5" innerstring. Started in well with 5" spear.

1-4 13th Day. Attached 5" spear to innerstring. Pulled innerstring from 7,395' to 7,555' out of well (Recovered 160'). Ran 6 5/8" casing scraper to 7,455' and circulated well. Ran 5" inside cutter to 7,875'. Cut 5" innerstring and started out of well.

1-5 14th Day. Finished pulling out of well with 5" cutter. Ran 5" spear to 7,555' and attached to 5" innerstring. Pulled out of well with innerstring from 7,555' to 7,875' (Recovered 320'). Started in well with 5" inside cutter

1979

History of Well Report for I.W. #70, Aliso Canyon

1-6 15th Day. Cut 5" innerstring at 8,190'. Ran 5" spear and attached to innerstring at 7,875'. Pulled out of well recovering 5" innerstring from 7,875' to 8,217'. Ran 6 5/8" casing scraper to 8,217', circulated well, and started out of well.

1-7 Rig and crew idle.

1-8 16th Day. Finished pulling out of well with 6 5/8" scraper. Ran 6 5/8" retrievable plug and retrievable retainer in well. Set plug at 8,200' and retainer at 8,185'. Pressure tested plug to 1,500 psi - OK. Started out of 6 5/8" casing, pressure testing below retrievable retainer. Isolated hole between 7,488' and 7,518'; had pressure loss of 500 psi in 2 minutes. Pressure tested annulus to 1,500 psi with retainer at 7,488'. Pressure loss of 500 psi in 1 minute. Continued testing 6 5/8" annulus to isolate top hole.

1-9 17th Day. Continued testing 6 5/8" annulus. Isolated top hole between 4,291' and 4,296'. Released retainer and pulled out of well. Reset retrievable bridge plug at 7,618'. Spotted 3 sacks of sand on retrievable plug and pulled out of well. Made up 300' of 2 3/8" tubing tail on retrievable retainer and started in well.

1-10 18th Day. Checked sand fill above retrievable plug at 7,618'. Mixed and spotted 5 sacks of sand on plug at 7,618'. Conditioned mud.

1-11 19th Day. With tubing tail at 7,530', mixed spotted and balanced 25 sacks (29 cu.ft.) of class "G" cement with 0.75% "CFR-2" from 7,530' to 7,380'. Pulled tail to 7,200', backscuttled drill pipe; set retrievable retainer and displaced 2 cu.ft. of cement out casing at 1,500 psi in 2 hours. Shut well in for four additional hours. Released retainer and pulled out of well. Started in well with 6 5/8" casing scraper and 5 5/8" bit.

1-12 20th Day. Drilled out cement from 7,488' to 7,530'; cleaned out to 7,598'. Ran retrievable retainer to 4,800'. Pressure tested below retainer to 1,000psi (Held OK). Started out of well.

1-13 21st Day. Finished pulling out of well with retrievable retainer. Made up 180' of tubing tail on 6 5/8" retainer; ran tail to 4,394'. With retainer at 4,204', spotted, equalized, and balanced 25 sacks of class "G" cement with 0.75% "CFR-2" from 4,394' to 4,244'. Pulled tail up to 4,210', backscuttled tubing and set retainer. Displaced 23 cu.ft. at 1,500 psi with pressure dropping to 1,200 psi. Shut well in for four hours. Released retainer and pulled out. Ran 6 5/8" bit and scraper to 5,000'. Did not find any cement. Started out of well.

1-14 Rig and crew idle.

1979 History of Well Report for I.W. #70, Alamo Canyon

1-15 22nd Day. Pulled out of well with bit and scraper. Made up Johnston "Positrieve" squeeze tool and ran in well. Set squeeze tool at 4,324'. Tested casing with 1,500 psi for 15 minutes, OK. Pulled up to 4,268' and set squeeze tool. Pressured up to 1,500 psi. Pressure bled down to 800 psi and held. Pulled out of well and made up Johnston "Bobcat" bridge plug. Ran in well and set bridge plug at 4,400'. With pipe hung at 4,396', pumped 5 sacks of sand on top of bridge plug. Tagged sand at 4,390' and pulled up to 2,000'.

1-16 23rd Day. Pulled out of well. Ran 8 5/8" squeeze tool with 381' of 2 3/8" tubing tail. With 2 3/8" tubing hung at 4,296', pumped 25 cu.ft. of water ahead of 50 sacks of class "G" cement with 0.75% "CFR-2" with 5 cu.ft. water behind. Displaced with 95 cu.ft. of mud. Pulled up to 3,816'. Backscuttled out. Set squeeze tool at 3,435'. Squeezed 3 cu.ft. out holes at 1,500 psi. Pulled out of well. Made up 5 5/8" bit and 6 5/8" casing scraper. Ran in well and drilled out cement from 4,046' to 4,325'. Cleaned out to 4,392'. Pulled up to top of 6 5/8" liner.

1-17 24th Day. Tested from 4,400' to surface with 1,000 psi for 20 minutes, OK. Pulled out of well with bit and scraper. Made up Johnston retrieving tool and ran in well. Circulated sand out and retrieved bridge plug from 4,400'. Ran in well and cleaned out sand from 7,593' to 7,618'. Retrieved bridge plug from 7,618'. Made up 3 7/8" bit and casing scraper. Ran in well to 2,362'.

1-18 25th Day. Ran in well with 3 7/8" bit and 4 1/2" casing scraper. Cleaned out fill from 8,522' to 8,672'. Changed over from 74# to 68# polymer completion fluid. Pulled out of well with bit and scraper (lost two cones in well). Made up Servco 3 7/8" mill on 2 3/8" tubing. Ran in well milling on junk. Pulled up to 7,983'.

1-19 26th Day. Ran in well. Milled on junk from 8,672' to 8,676'. Pulled out of well and made up Midway washover junk shoe with wire fingers inside. Ran in well. Washed over junk from 8,676' to 8,680'. Pulled out of well and recovered no junk. Ran in well to 2,000' with 3 7/8" mill.

1-20 27th Day. Pulled out of well. Made up Servco 3 3/4" junk mill and ran in well. Milled on junk from 8,680' to 8,687'. Pulled out of well. Made up Servco 3 3/4" "Econo-mill" and ran in well.

1-21 Rig and crew idle.

1-22 28th Day. Cleaned out with 3 3/4" O.D. Servco "Econo-mill" from 8,687' to 8,698'. Mill stopped. Pulled out of well, ran new 3 3/4" O.D. "Econo-mill" and cleaned out from 8,698' to 8,702'.

1-23 29th Day. Cleaned out well with Servco "Econo-mill" from 8,702' to 8,704'. Pulled out of well and ran 3 3/4" O.D. Servco junk mill. Measured in well. Corrected clean out depth to 8,764'. Started out of well.

1-24 30th Day. Ran 555' of 2 3/8" tubing tail on 2 7/8" drill pipe to 8,733'. Mixed spotted and balanced 5 sacks of sand in well. Filled from 8,764' to 8,748'. Mixed, spotted and balanced 10 additional sacks of sand in well, waited 2 hours and cleaned excess fill out to 8,712'.

1-25 31st Day. Tagged fill at 8,677'. Backscuttled out to 8,710' and pulled out of well. Ran 4 1/2" casing scraper to 8,710'. Pulled out of well. Made up 4 1/2" wash tools and started in well.

1-26 32nd Day. Washed liner from 8,710' to 8,230'. Pulled out of well with wash tool. Started in well with sawtooth collar on 600' of 2 3/8" tubing tail.

1-27 33rd Day. Cleaned out fill from 8,702' to 8,710'. Circulated well, then backscuttled well. Pulled out of well and installed 4 1/2" wash tools on 600' of 2 3/8" tubing. Started in well.

1-28 Rig and crew idle.

1-29 34th Day. Spotted 15% acid (10% HCL and 5% HF) to Atlas wash tools; washed from 8,710' to 8,620', acid back-check valve failed. Backscuttled acid out of well and started out of well. Drill pipe parted 1,024' from surface. Ran 7 5/8" x 3 7/8" Bowen overshot and 3 1/2" bumper sub to 1,024'; attached overshot to fish and pulled out of well. Recovered all fish (7,116' 2 7/8" drill pipe and 570' of 2 3/8" tubing with Atlas wash tool).

1-30 35th Day. Laid down and loaded out 2 7/8" drill pipe. Unloaded 2 7/8" tubing and started in well.

1-31 36th Day. Finished picking up 2 7/8" tubing. Installed 555' of 2 3/8" tubing tail and 4 1/2" wash tool on 2 7/8" tubing and started in well.

2-1 37th Day. Using 10% HCL and 5% HF acid with inhibitor, washed perforations from 8,710' to 8,230' (30 gallons per foot). Circulated spent acid out of well, and started out of well with wash tools.

2-2 38th Day. Pulled 4 1/2" washing tools out of well. Ran 6 5/8" Retrievable retainer to 8,212'. Pressure tested annulus at 1,000 psi for 30 minutes. Pulled 6 5/8" Retrievable retainer out of well. Ran 6 5/8" Otis "Permatrieve" packer and set at 8,194'. Started out of well with line when engine on truck failed. Shut well in with 8,000' of line in well by packing off lubricator and closing Hydril bag.

2-3 39th Day. Retrieved McCullough wireline from well leaving wireline setting tool and collar locator.

2-4 Rig and crew idle.

2-5 40th Day. Ran 4 11/16" O.D. x 2 1/2" overshot on 2 7/8" bumper sub to 8,194', attached to wireline setting tool and retrieved from well. Ran Otis seal assembly to 6 5/8" "Permatrieve" packer at 8,192'. Pressure tested to 500 psi, OK. Spotted inhibited mud from 8,190' to 3,800'. Pulled out of well laying down excess 2 7/8" tubing and 2 3/8" tubing tail.

2-6 41st Day. Finished pulling out of well. Set 8 5/8" Otis "Permatrieve"

2-6 Continued

packer on electric line at 3,915'. Ran Otis latch-type seal to packer and pressure tested to 1,500 psi, Ok. Pulled out of well, changing collars.

2-7 42nd Day. Made up Otis Production tube and 3.25" O.D. x 16' seal assembly on 3 1/2" Hydril flush joint tubing and started in well pressure testing to 5,000 psi for 1 minute.

2-8 43rd Day. Finished picking up 3 1/2" flush joint tubing; made up Otis 4" x 4' latch-type seal assembly, 10' blast joint, 2.25" NO-GO nipple, 20' blast joint, and 2 7/8" Otis Annular flow safety system; ran assemblys to their pack off seats; checked lower seal spacing when top packer latch was in place (6' of seals below packer, 8' of seals above packer). Installed doughnut and landed in tubing head with 10,800# setdown weight on top packer at 3,915'. Installed back pressure valve in doughnut. Removed BOPE and installed tree.

2-9 44th Day. Pressure tested tree and doughnut seals to 5,000 psi. Removed back pressure valve and retrieved Otis separation tool from safety mandrel. Displaced 68# polymer completion fluid from well with 63# lease water. Closed well in, blind flanged valves and released rig at 7:00 p.m.

Ex. I – 57

FORM 103

SUBMIT IN DUPLICATE

STATE OF CALIFORNIA

DEPARTMENT OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

History of Oil or Gas Well

OPERATOR GETTY OIL COMPANY, Operator FIELD ALISO CANYON

Well No. SFZU P-45, Sec. 27, T. 3N, R. 16W, S.B. B. & M.

Date March 3, 1969 Signed C. G. Nelson
C.G. Nelson

P.O. Box 811, Ventura, Calif. 643-2154 Title Agent
(Address) (Telephone Number) (President, Secretary or Agent)

It is of the greatest importance to have a complete history of the well. Use this form to report a full account of all important operations during the drilling and testing of the well or during re-drilling, altering of casing, plugging, or abandonment with the dates thereof. Be sure to include such items as hole size, formation test details, amounts of cement used, top and bottom of plugs, perforation details, sidetracked junk, bailing tests, shooting and initial production data.

1969
Date

HISTORY

1/15-21 C.P.S. Hoist moved in, rigged up. Rigged up swab and lubricator. Checked surface pipe and 7" casing, found pressures equalized - indicating possible casing failure at shallow depth, or packing leaking in head. Filled hole with 150 barrels salt water, circulated. Removed tree and installed B.O.P.E. Pulled tubing. Began running Johnston bridge plug; bridge plug stopped at 710'. Pulled out. Ran open ended tubing OK to 7497'. Circulated with lease water (6:30 A.M. to 3:00 P.M.) Pulled out. Ran 6" O.D. impression block OK to 850'; hit no tight spots, but reflected imprint of 7" casing stub, indicating casing possibly parted. Ran 6" bit and 7" casing scraper OK to 850': found no tight spots. Ran Johnston bridge plug to 7300'; pulled back - set bridge plug at 7220'. Circulated 1 1/2 hours, no gas in returns. Ran Johnston Tension 7" packer to 810': Tested 7" casing for leaks at 1500#. Found break in 7" casing at 177'. Tested packoff in 7" landing head to 500# O.K. Laid down Johnston tools. Ran 2 7/8" open end tubing to 3000' and circulated. Pulled out. Pulled casing from break at 178'. Ran Bowen 7" casing cutter, cut 7" casing at 185': Reran 7" casing with Burns 7" lead seal casing bowl. Retrieved bridge plug from 7300'. Circulated 2 hours. Reset plug at 240'. Tested casing OK. Laid down bridge plug. Hydrotested tubing and gas lift equipment. Could not set packer at 7485' or 7300'. Pulled out. Found 4' pup unscrewed from MM mandrel, left MM mandrel, 30' tubing and packer in hole. Ran Midway tools, recovered all of fish. Reran tubing, set packer OK at 7485'. Installed gas lift valves and packer and moved out.

Casing Record

10 3/4" 40.5# c 505'
7" 23 & 26# effec. to 7600'
Casing Bowl at 185'
WSO 4 h's 7390'*
J.P. 4 h's (Seg) 7510'(Cmtd);
7511' (Cmtd.) and 7444'
G.P. 4 h/ft 7520-7595'
Ineffec. Csg. Below Retainer at 7600'
48'-7" c 7648'
WSO shoe at 7648'*
G.P. 4 h/ft 7613-7633' (Cmtd.)
*Witnessed and approved by D.O.G.

DIVISION OF OIL AND GAS
RECEIVED
MAR 4 1969
INGLEWOOD, CALIFORNIA

FORM 111

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION

DIVISION OF OIL AND GAS

REPORT ON PROPOSED OPERATIONS No. P 169-248

Mr. C. G. Nelson, Agent
GETTY OIL COMPANY, OPERATOR
P. O. Box 811
Ventura, California 93002

Inglewood, Calif.
March 10, 1969

DEAR SIR:

Your proposal to alter casing Well No. "SFZU" P-45 (037-00732), Section 27, T. 3 N, R. 16 W, S.B. B. & M., Aliso Canyon Field, Los Angeles County, dated 3/3/69, received 3/4/69, has been examined in conjunction with records filed in this office.

With reference to your notice our decision is as follows:

DECISION
THE PROPOSAL IS APPROVED.

RR:nw

cc C. G. Nelson

Blanket Bond

F. E. KASLINE, State Oil and Gas Supervisor

By Robert Lindhauer, Jr., Deputy

FORM 107

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION

DIVISION OF OIL AND GAS

DIVISION OF OIL AND GAS
RECEIVED
MAR 4 1969
INGLEWOOD, CALIFORNIA

Notice of Intention to Deepen, Redrill, Plug or Alter Casing in Well

This notice must be given before work begins; one copy only

Ventura, Calif. March 3, 1969

DIVISION OF OIL AND GAS

In compliance with Section 3203, Chapter 93, Statutes of 1939, notice is hereby given that it is our intention to commence the work of ~~deepening, redrilling, plugging or~~ altering casing at Well No. "SFZU" P-45 (037-00732)
(Cross out unnecessary words)

, Sec. 27, T. 3N, R. 16W, S.B. B. & M.

Aliso Canyon Field, Los Angeles County.

The present condition of the well is as follows:

1. Total depth. T.D. 8835'; Pg. 7600'

2. Complete casing record, including plugs:
   10 3/4" 40.5# c 505'
   7" 23, 26# effec. to 7600'
   WSO 4 h's 7390'*
   J.P. 4 h's (Seg.) 7510' (Cmtd); 7511' (Cmtd) and 7444'
   G.P. 4 h/ft 7520-7595'
   Ineffec. Casing Below Retainer at 7600'
   48'-7" c 7648'
   WSO shoe at 7648'*
   G.P. 4 h/ft 7613-7633' (Cmtd)
   *Witnessed and approved by D.O.G.

3. ~~Last produced~~ Presently flowing 58 BOPD; 2 BWPD; 290 MCF
   (Date) (Oil, B/D) (Water, B/D) (Gas Mcf/D)

The proposed work is as follows: Repair 7" casing (parted at 185') with Burns casing bowl.

Alter casing

MAP	MAP BOOK	CARDS	BOND	FORMS 114	FORMS 121
			B	ARG	ARG

P.O. Box 811, Ventura, Calif.
(Address)

643-2154
(Telephone No.)

GETTY OIL COMPANY Operator
(Name of Operator)

By C. G. Nelson
C.G. Nelson, Agent

ADDRESS ONE COPY OF NOTICE TO DIVISION OF OIL AND GAS IN DISTRICT WHERE WELL IS LOCATED

Getty Oil Company P.O. Box 811, Ventura, California 93001 | (805) 643-2154

March 3, 1969

DIVISION OF OIL AND GAS
RECEIVED
MAR 4 1969
INGLEWOOD, CALIFORNIA

Division of Oil & Gas
830 N. La Brea Avenue
Inglewood, California 90302

Gentlemen:

In reviewing the well history on our well SFZU P-45, it was determined that no Form 107 (Notice of Intention to Perform Work) had been submitted to your office outlining a recent casing repair.

On January 15, 1969 the well was entered for routine remedial work, at which time the 7" casing was found to be parted at 178'. The casing was pulled from the depth of the part, and cut at 185'. A Burns casing bowl was run with 7" casing and set at 185'.

The attached form 107 and Well History detail the work performed.

Very truly yours,

GETTY OIL COMPANY

C. G. Nelson

C. G. Nelson, Agent

EJH:brm

Attachments

Ex. I – 58

SUBMIT IN DUPLICATE

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION

DIVISION OF OIL AND GAS

DIVISION OF OIL AND GAS
RECEIVED
DEC - 1 1977
SANTA PAULA, CALIFORNIA

History of Oil or Gas Well

Operator SOUTHER CALIFORNIA GAS COMPANY Field or County Aliso Canyon
Well name and No. STANDARD SESNON #12, Sec. 29, T 3N, R 16W, S.B.B. & M.
A.P.I. well No. 037-00764 Name P. S. Magruder, Jr. (Person submitting report) Title Agent (President, Secretary or Agent)
Date November 7, 19 77

Signature P. S. Magruder

P. O. Box 3249, Terminal Annex, Los Angeles, California 90051 (Address) (213) 689-3561 (Telephone Number)

History must be complete in all detail. Use this form to report all operations during drilling and testing of the well or during redrilling or altering the casing, plugging, or abandonment with the dates thereof. Include such items as hole size, formation test details, amounts of cement used, top and bottom of plugs, perforation details, sidetracked junk, bailing tests and initial production data.

Date	
1977	
9- 9	Killed well using 74#/cu.ft. polymer drilling fluid.
9-10	Moved California Production Service Rig #D-4 from Frew #2 to Standard Sesnon #12 and rigged up.
9-11	Rig and crew idle.
9-12	Finished rigging up. Circulated polymer fluid in well to remove gas-cut drilling fluid. Tested wellhead seals. Removed Christmas tree and installed B.O.P.E. Tested with water pipe rams and blind rams to 4000 psi for 20 minutes each test. Tested Hydril bag to 3000 psi for 20 minutes. These tests were witnessed and approved by D.O.G. Conducted similar tests, using nitrogen - all tests O.K. Unseated production string from packers. Pulled above packers. Circulated polymer drilling fluid.
9-13	Pulled production string out of well. Ran in well with 6" bit and casing scraper. Stopped at 3453' or 79' above 7" x 6 5/8" crossover. Circulated polymer drilling fluid to clean well. Bled off annulus between 9 5/8" x 13". Ran in well to 8733' with sawtooth collar and 14 joints of 2 3/8" Hydril.
9-14	Cleaned fill from 9062' to 9107' with sawtooth collar. Circulated polymer drilling fluid to clean well. Pulled out and ran back in with Baker "DR" plug. Set "DR" plug in Baker packer at 8744'. Tested plug to 2000 psi. Replaced polymer drilling fluid in well with fresh water.
9-15	Pulled out of well. Ran in well with Baker fullbore and set at 3100'. Tested casing from 3100' to 8744' 2800 psi for 60 minutes. Tested from 3100' to surface at 3000 psi - indications of leak. Pulled to 2180' and started testing casing between surface and 2180' at 3000 psi - pressure dropped suddenly to zero. (Designed testing pressure 3500 psi). Filled 7" casing annulus with 115 cu.ft. water. Pumped more water at 100 psi in 7" casing, annulus pressure rose in 7" x 9 5/8" annulus. Tested from 2180' to 8744' at 1000 psi.

9-16 Pulled out of well. Ran back in open-ended to 8744' and replaced fresh water in well with brine-polymer drilling fluid. Pulled out of well. Ran back in with Baker full-bore. Located leak in 7" casing between 553' and 554' - final testing as follows:

Surface to	553'	at 1800 psi	- O.K.
" "	554'	" " "	- unable to hold pressure
554' "	8744'	" 1000 psi	- O.K.

Ran 17 more stands to secure well.

9-17 Tested 7" casing from 580' to 8740' at 2500 psi for 30 minutes - O.K. Pulled out of well and ran back in with Baker Lok-Set bridge plug and set it at 920'. Tested plug at 500 psi. Spotted 5 cu.ft. of sand on top of plug. Tagged top of sand, pulled out and ran back in with cutting knives. Made cut in 7" casing at 615'. Pulled out and ran back in ten stands to secure well.

9-18 Rig and crew idle.

9-19 Removed B.O.P.E. Unlanded 7" casing and recovered 12 1/2 joints to parted casing at 553'. Pin of Speedtite thread (Hydril EU) was damaged and jumped out of damaged box causing a leak in the casing. Ran spear and recovered 62' of 7" casing from where cut at 615'. Casing all in good condition except for one damaged connection at 553'. Ran mill and dressed stub of 7" casing at 615'. Pumped inhibitor treated brine-polymer drilling fluid in well and pulled out. Removed 10" x 13" spool to replace leaking 9 5/8" packing.

9-20 Casing (9 5/8") was cut off at top of casing head and therefore was no 9 5/8" secondary seal. Cleaned cellar. Removed packing from 9 5/8". Picked up 9 5/8" spear and installed casing jacks. Preparing to unland 9 5/8" and repair 13 3/8" casing.

9-21 Unlanded 9 5/8" casing. Found that 13 3/8" casing was parted near cellar floor. Jack-hammered out 12" of cellar. Cut off 13 3/8" casing and butt welded with casing head. This lower casing head will allow secondary seal on 9 5/8" intermediate casing.

9-22 Checked 13 3/8" butt weld with X-Ray. Landed 9 5/8" casing on slips with 160,000#. Packed off 9 5/8" and installed spool. Pressure tested 9 5/8" seals under 3000 psi. Ran Bowen casing bowl over 7" stub at 615'. Pulled 60,000#. Pressure tested 7" casing from surface to 900' under 4000 psi.

9-23 Landed 7" casing on slips in spool with 200,000# using casing jacks. Cut off 7" and installed B.O.P.E. Tested blind rams and 7" casing to 900' with 4000 psi for 20 minutes, using water. Tested seals on 7" to 4000 psi for 20 minutes. Tested blind rams with nitrogen to 4000 psi for 20 minutes.

9-24 Ran in hole with Baker retrieving tool which would not go through casing bowl. Pulled out of hole. Removed B.O.P.E. Picked up 7" casing. Pulled out of hole, laying down 7". Recovered all new 7" 8rd casing and 274' of 7" Speedtite casing from parted connection. Top of 7" at 889'. Ran impression block on tubing - showed 7" casing. Ran casing cutter. Located sand at 910'. Cut 7" casing at 900'.

9-25 Rig and crew idle.

9-26 Pulled out with casing cutter. Ran back in with spear and recovered 10' cut piece of 7" casing top at 900'. Ran in with casing dressing tool. Dressed 7" casing stub for one hour. Pulled out. Ran in with impression block. Impression block showed rough edge of casing stub. Ran in with Baker retrieving tool and circulated polymer drilling fluid to remove sand from top of plug at 920'. Retrieved bridge plug and reset plug at 1400'. Spotted 5 sacks of sand on top of plug. Ran in and made inside cut in 7" casing at 1070'. Pulled out. Ran in with spear and recovered casing.

9-27 Pulled out 181' of 7" casing. Ran in with casing dressing tool. Dressed 7" casing stub for one hour. Pulled out. Ran in with impression block. Pulled out. Ran in with Bowen casing bowl and 27 joints of 7" casing. Latched on to 7" casing stub. Pulled 200,000# and set in casing slips. Started pressure testing 7" casing between surface and 1400' to 3500 psi. Casing parted at 3200 psi pressure. Pulled out 7" casing up to casing bowl.

9-28 Pulled out 154' of old 7" casing where the Speedtite joint had parted top of 7" stub at 1224'. Ran in well with Baker retrieving tool. Circulated polymer drilling fluid to remove sand from top of Baker bridge plug at 1400'. Recovered bridge plug and pulled out. Ran in with 6 5/8" Baker Lok-Set plug and set same at 4000'. Spotted 5 cu.ft. of sand on top of bridge plug. Pulled out. Ran in with Midway spear and latched same near top of stub. Ran McCullough free-point on wireline. Limited pulling capacity indicated movement of 7" and 6 5/8" casing at least down to 3700'. Pulled out. Ran in with inside cutter to make a cut in 6 5/8" casing at 3600'.

9-29 Ran inside casing cutter to 3600' and made cut in 7" casing. Pulled out. Ran in well with spear and latched onto casing and tried to pull. Unable to pull casing. Pulled out of well and ran back in with casing cutters and made cut at 2429'. Pulled out. Ran in with spear and latched onto casing and started pulling out. Pulled out 14 joints of 7" Speedtite and 25 joints of 7" 8rd casing.

9-30 Ran in well with 7" spear, jars and bumper sub to top of 7" casing stub at 2429'. Pulled loose and laid down with 7" and 6 5/8" casing. Top of

6 5/8" casing stub at 3600'. Ran in well with Midway dressing tool, worked on top of stub for one hour. Circulated bottoms up and pulled out.

10-1 Ran in well with impression block. Pulled out. Impression block showed inside dimension of 6 5/8" casing. Ran 7" casing with 6 5/8" Bowen casing bowl and latched on to 6 5/8" stub at 3600'. Landed casing with 150,000#. Installed slips and packing. Cut off 7" casing. Pressure tested casing seals. Reinstalled B.O.P.E.

10-3 Tested casing from 4000' to surface with 3700 psi for 20 minutes - O.K. Ran in to 3871' and displaced brine-polymer drilling fluid with fresh water containing surfactant. Tested casing from 4000' to surface with 3000 psi for 60 minutes - O.K. Recovered bridge plug. Ran Baker fullbore cementer to 2180'. Tested casing from 2180' to surface with 3500 psi for 60 minutes - O.K. Pulled to 800' and tested casing from 800' to surface with 4000 psi for 60 minutes - O.K. Pulled fullbore tool and started in well with Baker retrieving tool.

10-4 Ran to 4000'. Displaced water with brine-polymer drilling fluid. Recovered "DR" plug from packer at 8756'. Assembled seals and safety system and hydrotested to 5000 psi. Ran tubing, changing couplings, applying Baker seal and hydrotesting to 5000 psi.

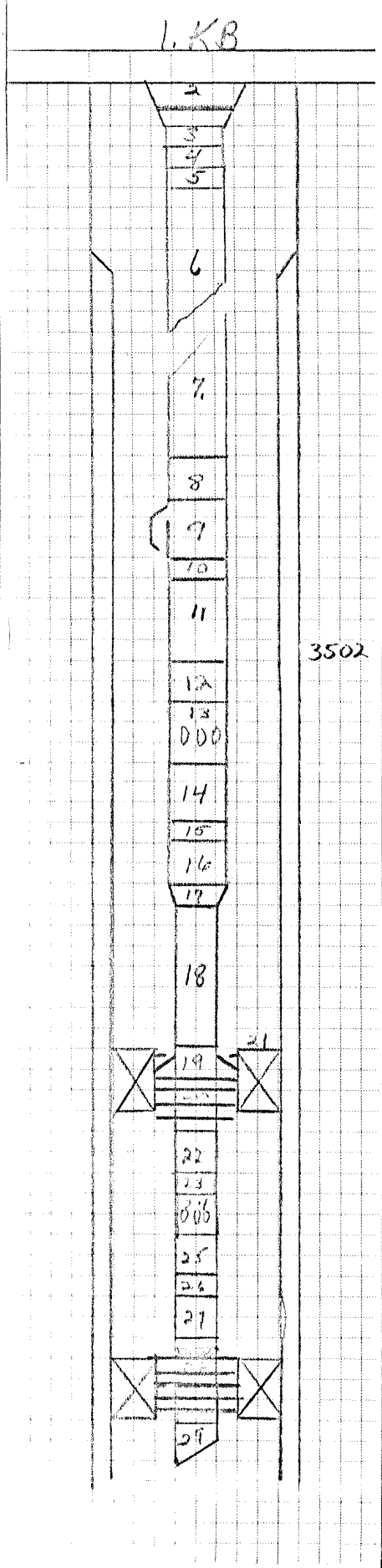
10-5 Re-ran tubing while changing collars, cleaning threads, applying Baker seal and hydrotesting to 5000 psi.

10-6 Continued running completion tubing string, changing couplings, applying Baker seal and hydrotesting to 5000 psi.

10-7 Landed tubing with 10,000# on packer at hook load of 52,000#. Checked latch with 25,000# pull over weight of tubing. Installed tubing hanger plug and removed B.O.P.E. Reinstalled Christmas tree and pressure tested to 5000 psi. Displaced brine-polymer fluid with waste salt water. Ran tubing plug, unable to find NO-GO nipple at 8416'. Left Otis plug in 2 7/8" x 2 3/8" X-over at 8427'. Ran 2.215" plug which was set in safety system at 8395'. Pressure tested packer and seals with 2000 psi for one hour.
RIG RELEASED at 10:00 P.M. (10/7/77).

JP

WELL PROFILE



OPERATOR SOUTHERN CALIFORNIA GAS COMPANY

WELL # STANDARD SESNON #12

FIELD Aliso Canyon

COUNTY Los Angeles

STATE California

DATE October 11, 1977

☐ NEW COMPLETION XXXWORKOVER

	CASING	LINER	TUBING 1	TUBING 2	TUBING 3
SIZE					
WEIGHT					
GRADE					
THREAD					
DEPTH					

ITEM NO.	TUBING DETAILS	LENGTH	DEPTH
1.	K.B.	15.00	15.00
2.	Doughnut	.80	15.80
3.	Pup Joint 2 7/8" N-80 EUE 8rd	1.00	16.80
4.	Pup Joint 2 7/8" N-80 EUE 8rd	4.00	20.80
5.	Pup Joint 2 7/8" N-80 EUE 8rd	6.00	26.80
6.	26 Joints 2 7/8" N-80 EUE 8rd Tubing	775.37	802.17
7.	244 Joints 2 7/8" J-55 EUE 8rd Tubing	7540.47	8342.64
8.	Pup Joint N-80 2 7/8" EUE 8rd	4.09	8346.73
9.	Gas Lift Mandrel (EMPTY)	8.32	8355.05
10.	Pup Joint N-80 2 7/8" EUE 8rd	1.80	8356.85
11.	1 Joint 2 7/8" J-55 EUE 8rd Tubing	30.59	8387.44
12.	Pup Joint 2 7/8" N-80 EUE 8rd	4.11	8391.55
13.	Otis Tubing Flow Safety System (EMPTY)	3.73	8395.28
14.	Blast Joint 3 5/8" O.D.	19.89	8415.17
15.	Nipple 2.205" NO-GO	1.16	8416.33
16.	Blast Joint 3 5/8" O.D.	9.86	8426.19
17.	X-Over 2 7/8" EU x 2 3/8" EU	1.05	8427.24
18.	10 Joints 2 3/8" EUE 8rd Tubing	328.76	8756.00
	Baker Model "D" Packer	.....	8756.00
19.	Baker Latch	1.05	8757.05
20.	4 Seals	3.30	8760.35
21.	2 Joints 2 3/8" EUE 8rd Tubing	59.60	8819.95
22.	Pup Joint 2 3/8" EUE 8rd J-55	6.00	8825.95
23.	Otis Sliding Side Door (OPEN)	2.86	8828.81
24.	3 Joints 2 3/8" J-55 EUE 8rd Tubing	89.39	8918.20
25.	NO-GO 1.536" Nipple X-N	1.11	8919.31
26.	1 Joint 2 3/8" EUE 8rd Tubing	31.44	8950.25
	Baker Model "D" Packer	.....	8950.00
27.	10 Baker Seals	8.80	8959.55
28.	Production Tube	5.85	8965.40

COMMENTS:

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION

DIVISION OF OIL AND GAS

Report on Operations

No. T 277-271

Mr. P. S. Magruder, Jr., Agent
Southern Calif. Gas Co.
P.O. Box 54790 Terminal Annex
Los Angeles, Calif. 90054

Santa Paula, Calif.
Oct. 6, 1977

DEAR SIR:

Operations at well No. "SFZU" SS-12, API No. 037-00764, Sec. 29, T. 3N, R. 16W, S.B., B & M. Aliso Canyon Field, in Los Angeles County, were witnessed on 9/12/77. Mr. T. E. Adams, representative of the supervisor was present from 1730 to 1900. There were also present Jeevan Anand, reservoir engr.

Present condition of well: No additions to the casing record since proposal dated 9/13/77.

The operations were performed for the purpose of testing the blowout prevention equipment and installation.

DECISION:

THE BLOWOUT PREVENTION EQUIPMENT AND INSTALLATION ARE APPROVED.

b

M. G. MEFFERD
~~JOHN F. MATTHEWS, JR.~~
State Oil and Gas Supervisor

By John L. Hardoin Deputy
John L. Hardoin

No. P277-333

REPORT ON PROPOSED OPERATIONS

Santa Paula, California

Sept. 13, 1977

Mr. P. S. Magruder, Jr., Agent
Southern Calif. Gas Company
P.O. Box 54790 Terminal Annex
Los Angeles, Calif. 90054

Your rework proposal to gas storage well "SFZU" SS-12 (Name and number), A.P.I. No. 037-0764, Section 29, T. 3N, R. 16W, S.B. B. & M., Aliso Canyon field, Los Angeles County, dated 9-3-77, received 9-12-77, has been examined in conjunction with records filed in this office.

THE PROPOSAL IS APPROVED PROVIDED THAT:

1. The drilling fluid used shall be of a quality and in sufficient quantity to control all subsurface conditions in order to prevent blowouts; and a reserve supply of this material shall be kept on hand to meet any emergency.
2. Blowout prevention equipment, at least of the Division of Oil and Gas Class III,3M rating, shall be installed and maintained in operating condition at all times.
3. THIS DIVISION SHALL BE NOTIFIED TO WITNESS A PRESSURE TEST OF THE BLOWOUT PREVENTION EQUIPMENT BEFORE COMMENCING DOWNHOLE OPERATIONS.

Blanket Bond
MD:b

NOTE: A COPY OF THIS APPROVAL SHALL BE POSTED AT THE WELL SITE PRIOR TO COMMENCING OPERATIONS.

M. G. MEFFERD
State Oil and Gas Supervisor

By John L. Hardoin
Deputy Supervisor

John L. Hardoin

OG111 (11-76-GSR1-30M)

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION

DIVISION OF OIL AND GAS

Notice of Intention to Rework Well

DIVISION OF OIL AND GAS
RECEIVED
SEP 12 1977
SANTA PAULA, CALIFORNIA

This notice and indemnity or cash bond shall be filed, and approval given, before rework begins. If operations have not commenced within one year of receipt of the notice, this notice will be considered cancelled.

FOR DIVISION USE ONLY		
BOND	OGD114	OGD121
BB	✓	✓

DIVISION OF OIL AND GAS

In compliance with Section 3203, Division 3. Public Resources Code, notice is hereby given that it is our intention to rework well No. STANDARD SESNON #12, API No. 037-00764, Sec. 29, T. 3N, R. 16W, S.B. B. & M., Aliso Canyon Field, Los Angeles County.

The present condition of the well is as follows:

1. Total depth. 9112' - cement plug 9107'

2. Complete casing record, including plugs and perforations:

   13 3/8" cemented 790'
   9 5/8" " 3770' - milled section
   7" and 6 5/8" cemented 9110', squeezed 8817'
   WSO 8816', squeezed 8880', segregation 8958'
   Perforated 9107' - 9055', 9045' - 8963', 8935' - 8880'
   8870' - 8825'.
   202' 5" landed 8690' - top 8488' lead seals

3. Present producing zone name Sesnon Zone in which well is to be recompleted --

4. Present zone pressure 3650 psi New zone pressure --

5. Last produced Gas Storage Well _____ _____ _____
   (Date) (Oil, B/D) (Water, B/D) (Gas, Mcf/D)

   or

6. Last injected _____ _____ _____ _____
   (Date) (Water, B/D) (Gas, Mcf) (Surface pressure, psig.)

The proposed work is as follows:

1. Move in and rig up. Kill well. Install BOPE and pressure test.
2. Clean out to 9107'. Pressure test 6 5/8" and 7" casings.
3. Perform any remedial work indicated by pressure testing.
4. Run tubing with down hole safety system.
5. Return well to gas storage operation.

It is understood that if changes in this plan become necessary we are to notify you immediately.

Address P.O. Box 3249 Terminal Annex
(Street)
Los Angeles California 90051
(City) (State) (Zip)
Telephone Number (213) 689-3561

Southern California Gas Company
(Name of Operator)
By P.S. Magruder Jr.
(Name) P.S. Magruder, Jr. (Date) 9-3-77
Type of Organization Corporation
(Corporation, Partnership, Individual, etc.)

OG107 (8-75—GSRI—15M)

DIVISION OF OIL AND GAS
RECEIVED
SEP 12 1977
SANTA PAULA, CALIFORNIA

STANDARD SESNON #12 - ALISO CANYON

Program to pressure test casing and install new down hole safety system.

TUBING WITHDRAWAL ONLY

Take all measurements from original derrick floor 9' above ground.

PRESENT CONDITIONS:

13 3/8" cemented 790' 54-5# J-55
9 5/8" cemented 3770' milled section
7" and 6 5/8" cemented 9110' squeezed 8817'
WSO 8816', squeezed 8880', segregation 8958'
3502' 7" - 6 5/8" 3502' - 9110'
Perforated 9107' - 9055'
9045' - 8963'
8990' - 8935'
8870' - 8825'
202' 5" landed 8690', top 8488'
15# Hydril flush joint
Lead seals top and bottom (covers tight 6 5/8" casing)

CASING DETAILS:

			80% Safety Factor BURST	COLLAPSE
7"	0 - 376'	23# N-80	5070	3440
	376' - 1809'	23# J-55	3490	2630
	1809' - 2048'	23# N-80	5070	3440
	2048' - 3502'	23# J-55	3490	2630
6 5/8"	3502' - 3852'	28# J-55	4840	4360
	3852' - 7120'	24# N-80	5950	4440
	7120' - 8560'	24# N-80	5950	4440
	8560' - 9110'	28# N-80	7050	5700

TUBING DETAIL:

Baker Model "D" packer 8950' (6 5/8")
Baker Model "D" packer 8756' (6 5/8")
2 3/8" and 2 7/8" tubing landed 8952'
Baker "R" nipple (2 3/8") 8947'
Baker sliding sleeve (2 3/8") 8840' open
Baker "F" nipple (2 3/8") 8714'
Baker "F" nipple (2 3/8") 8683'
Baker sliding sleeve (2 3/8") 8651' open
Cameo gas lift mandrel with dummy 8440'

PROGRAM:

1. Move in and rig up.

2. Open sliding sleeve at 8651'. Kill well with 72#/cu. ft. brine polymer drilling fluid. Check bottom hole pressure before moving in rig. Volume of well = 335 barrels.

3. Install back pressure valve in doughnut. Remove Xmas tree and install class III 5000 psi BOPE. Pressure test complete shut-off rams and pipe rams to 4000 psi with water and nitrogen. Also pressure test Hydril bag to 3000 psi with water and nitrogen.

4. Pull tubing. Run special clearance tubing (packer bore 3.25") and clean out to 9107' using saw tooth collar.

5. Run 6 1/8" bit and casing scraper. Clean out to 3502'.

6. Plug Model "D" packer 8950' and pressure test plug in packer with rig pump. Circulate polymer drilling fluid out of well with fresh water treated with surface tension agent. Pressure test casing, using cement retainer and cement pump truck equipped with calibrated pressure chart and pressure gauge, as follows:

3100'	to 8950'	with	2800 psi	for	60	minutes
Surface	" 3100'	"	3000 psi	"	60	"
"	" 2180'	"	3500 psi	"	60	"
"	" 800'	"	4000 psi	"	60	"

Change to polymer drilling fluid.

7. Perform any remedial work indicated by pressure testing. Pull plug from Model "D" packer.

8. Run 2 3/8" and 2 7/8" 8rd EUE J-55 tubing, change collars, clean pins, apply Baker seal and hydrotest to 5000 psi holding each test for one minute. Tubing to include:

Baker 2 3/8" production tube
Baker 10 seals
Baker 2 3/8" sliding sleeve (open)
Baker 4 seals
Baker Latch-in-locator
Otis 10' heavy wall tube
" 1.56" "NOGO" nipple with 2 3/8" threads
" 20' heavy wall tube
" tubing flow safety system
One joint 2 3/8" tubing
Otis empty gas lift mandrel
2 3/8" tubing to 8400', 2 7/8" tubing to surface with 800' of 2 7/8" 8rd EUE N-80 on top

9. Land tubing on packer with up to 10,000 pounds on packer - pull up to 25,000 pounds over weight of tubing to check latch.

PROGRAM: (Concluded)

10. Install back pressure valve in doughnut. Remove BOPE and reinstall Xmas tree. Pressure test Xmas tree to 5000 psi. Retest well head seals to 3500 psi.

11. Circulate brine polymer drilling fluid out of well with waste salt water. Set tubing plug in "NOGO" nipple and pressure test seals and packer to 2000 psi. Remove tubing plug and release rig.

G. C. ABRAHAMSON
July 13, 1977

cc: Rig Supervisor
Contract Pusher (2)
Relief Rig Supervisor
D.O.G. (S.P.)
B. Jones
D. Smiley
J. Melton
D. Justice)
M. Grijalva)

Well File
Spare Copy

GCA/jp

Ex. I – 59

Rec'd 09-01-17 DOGGR Ventura.

Well
Porter 42B

API #: 04-037-21877-00
Sec 28, T3N, R16W

Current Well Configuration

Operator: So. California Gas Co.

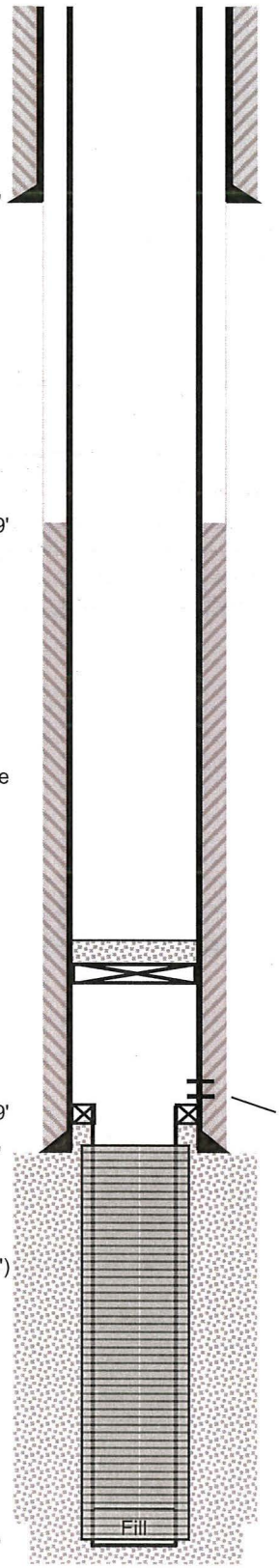
Lease: Porter
Field: Aliso Canyon
Status: Active Gas Storage
BFW: ±800' (±800')
USDW:

Ground Elevation: 1963' asl
Datum to Ground: 22' KB

Spud Date: 12/9/1978
Completion Date: 2/11/1979
Last Rework Date: 6/18/2016

Junk: None

Notes
USIT log run on 1/11/1992 detected minor CSG damage @ 7488' - 7490'. Anomoly is likely either parted CSG or a landing collar. Pressure Test between 7358' - 7552' Held, 6/1/2016.



13-3/8" TOC Surface

17-1/2" Hole

Surface Casing
13-3/8" (12.615" ID), 54.5#, K-55, BT&C
0' - 1020'

1020'

CMT'D w/ 1058 CF,
200 CF Returns to Surface

8-5/8" ETOC 3289'

Well Filled w/ 8.5 ppg HEC polymer

12-1/4" Hole

Production Casing
8-5/8" (7.825" ID), 36#
0' - 4082' K-55, LT&C
4082' - 7598' N-80, BT&C

CMT'D w/ 1853 CF (f/ 7610', later milled 8-5/8" f/ 7598' - 7610')

7181' Top of Sand (7 SKS)
7185' Lokset RBP (COE @ 7191', 6/16/2016)
7234' - 7244' Leak off to 1000 psi in 10 min. (6/1/2016)

7488' - 7490' See Notes
7498' - 7499' Four (4) 1/2" Holes WSO (1/27/79)
7500' Four (4) Holes (89 CF CMT SQZ'D Away, 1/24/79)

SC1 PCKR (6/12/2016) 7555' - 7569'

7598'

15" Hole (7598' - 7816')

Liner Perfs:
7588' - 7822' 0.012" WWS

Gravel Packed w/
484 CF (264% of Calc'd) 20-40

Liner (1/9/2013)
5" (4.408" ID), 15#, L-80, BT&C
7555 - 7823'

13" Hole (7816' - 7850')

7823'

7796' Unable to Clean Out Below (6/4/2016)

Top of Zone Markers	md	(tvd)
A1	4046'	(4045')
A36	4925'	(4911')
UP	5188'	(5161')
LP	5632'	(5584')
UDA1	5995'	(5928')
MDA	6731'	(6617')
LDA	6859'	(6738')
MP	7332'	(7185')
S1	7524'	(7367')
S4	7596'	(7435')
S8	7695'	(7529')

TD 7850'
TVD (7677)
Directionally Drilled: Yes (TD is 237' E, 991' N of Surf)

Prepared by: LD (4/26/2016)
Updated by: CAM (8/18/2017)
InterAct

Ex. I – 60

SUBMIT IN DUPLICATE

RESOURCES AGENCY OF CALIFORNIA
DEPARTMENT OF CONSERVATION

DIVISION OF OIL AND GAS

History of Oil or Gas Well

Operator Southern California Gas Co. Field or County Aliso Canyon
Well Porter #42-B, Sec. 28, T 3N, R 16W, SB B. & M.
A.P.I. No. 037-21877 Name P.S. Magruder Jr. (Person submitting report) Title Agent (President, Secretary or Agent)
Date February 27, 1979, 19

Signature P.S. Magruder Jr.

P.O. Box 3249 Terminal Annex, Los Angeles, Ca. 90051 (Address) (213) 689-3561 (Telephone Number)

History must be complete in all detail. Use this form to report all operations during drilling and testing of the well or during redrilling or altering the casing, plugging, or abandonment with the dates thereof. Include such items as hole size, formation test details, amounts of cement used, top and bottom of plugs, perforation details, sidetracked junk, bailing tests and initial production data.

Date	
1978	Program: Move Kenai-Camrich drilling Co. rig #23 onto wellsite, which is approximately 2,666.68' South and 2,519.6' West of Station #84, Aliso Canyon gas storage field. Drill and complete as a gas storage well in the S-4 sand with an approximate bottom hole location of 980' North and 230' West of surface location.
12-4	12-4 through 12-8-78, moved Kenai-Camrich Rig #23 onto wellsite and rigged up.
12-9	0Day. Completed rig up. Mixed mud and drilled rat hole with Dyna-drill. Spudded in at 4:00 p.m., December 9, 1978, drilled 17 1/2" hole to 206'. Mud wt. 64#, Vis. 58 sec.
12-10	1st Day. Drilled 17 1/2" hole from 206' to 581' with bit #1 and to 737' with bit #2. Mud wt. 72#, Vis. 52 sec., W.L. 14.8cc., solids 14%.
12-11	2nd Day. Drilled 17 1/2" hole from 737' to 995' with bit #2 and to 1,020' with bit #3. Circulated hole clean and pulled out to run 13 3/8" casing. Ran 26 joints of 13 3/8" K-55 Buttress casing, equipped with a B & W float guide shoe, 3 scratchers, 2 centralizers and a stop ring in top of first collar. Total on hook 1,023.26' including shoe.
12-12	3rd Day. With 13 3/8" casing shoe at 1,020' and stop ring at 984', Dowell cementers pumped 100 cu.ft. of water with green dye ahead of

History of Well Report for Porter #42-B, Aliso Canyon

1978

12-12 continued

438 sacks of class "G" cement plus 8% gel and 3% calcium chloride and, followed by 200 sacks of class "G" cement plus 3% calcium chloride and displaced with 857 cu.ft. of mud. Bumped plug with 750 psi. Cement in Place at 4:10 a.m.. Had approximately 200 cu.ft. of cement return to surface. Landed casing, welded on casing head and X-rayed same.

12-13 4th Day. Installed BOPE and tested blank rams to 2,700 psi with water and nitrogen for 20 minutes, ok. Made up drilling assembly and ran in hole. Pressure tested pipe rams, "GK" Hydril, upper and lower Kelly cocks, standpipe valves, and manifold to 2,700 psi with water and nitrogen for 20 minutes, ok. Witnessed and approved by D.O.G.

Mud wt. 71#, Vis. 40 sec., W.L. 14.4cc., solids 14%, sand 2%.

12-14 5th Day. Drilled 12 1/4" hole from 1,020' to 1,363' with bit #4 and to 1,630' with bit #5.

Mud wt. 75#, Vis. 42 sec., W.L. 8.4cc., sand 2%, solids 14%.

12-15 6th Day. Drilled 12 1/4" hole from 1,630' to 1,840' with bit #5 and to 2,093' with bit #6.

Mud wt. 73#, Vis. 45 sec., W.L. 8.7cc., sand 1%, solids 14%.

12-16 7th Day. Drilled 12 1/4" hole from 2,093' to 2,150' with bit #6 and to 2,405' with bit #7.

12-17 8th Day. Drilled 12 1/4" hole from 2,405', to 2,763' with bit #8 and to 2,991' with bit #9.

Mud wt. 71#, Vis 42 sec., W.L. 9.2cc., sand 1/2%, solids 11%.

12-18 9th Day. Drilled 12 1/4" hole from 2,991' to 3,031' with bit #9, to 3,279' with bit #10 and 3,390' with bit #11.

Mud wt. 73#, Vis 42 sec., W.L. 9.2cc., sand 1/2% solids 11%.

12-19 10th Day. Drilled 12 1/4" hole from 3,390' to 3,529' with bit #11 and to 3,778' with bit #12.

Mud wt. 72#, Vis 40 sec., W.L. 8.6cc., sand 1/2% solids 9%.

12-20 11th Day. Drilled 12 1/4% hole from 3,778' to 4,155' with bit #13. Dyna-drilled 12 1/4" hole from 4,155' to 4,180' with bit #14 on Dyna-drill #1.

Mud wt. 72#, Vis 39 sec., W.L. 8.4cc., Sand 1/2%, solids 8%.

12-21 12th Day. Dyna-drilled 12 1/4" hole from 4,180' to 4,208' with bit #15 and to 4,244' with bit #16 on Dyna-drill #1-B.

Mud wt. 72#, Vis. 40 sec., W.L. 7.6cc., sand 1/2%, solids 7%.

12-22 13th Day. Dyna-drilled 12 1/4" hole from 4,244' to 4,305' with bit #17 and to 4,312' with bit RR#16 on dyna-drills #1-C and #1-D guided by Eastman "DOT" tool.

Mud wt. 71#, Vis, 38 sec., W.L. 7.5cc., sand 1/4%, solids 7%.

12-23 14th Day. Dyna-drilled 12 1/4" hole from 4,312' to 4,367' with RR bit #16 on Dyna-drill #1-D. Directionally drilled 12 1/4" hole to 4,394' with bit #18.

Mud wt. 71#, Vis 40 sec., W.L. 6.8cc., sand 1/4%, solids 6%.

12-24 15th Day. Directionally drilled 12 1/4" hole from 4,393' to 4,463' with bit #18. Ran in with Dyna-drill #2 and bit #19.

Mud wt. 70#, Vis. 38 sec., W.L. 6.9cc., sand 1/45, solids 6%.

12-25 16th Day. Dyna-drilled 12 1/4" hole from 4,463' to 4,514' with bit #19 on Dyna-drill #2. Directionally drilled 12 1/4" hole from 4,514' to 4,553' with bit #20.

12-26 17th Day. Directionally drilled 12 1/4" hole from 4,553' to 4,804' with bit #20 and to 5,075' with bit #21. Reamed from 4,800' with bit #22.

Mud wt. 70#, Vis. 40 sec., W.L. 7.2cc., sand 3/4%, solids 8%.

12-27 18th Day. Reamed from 4,831' to 5,075'. Directionally drilled 12 1/4" hole from 5,075' to 5,337' with bit #22 and to 5,451' with bit #23.

Mud wt. 70.5#, Vis. 43 sec., W.L. 6.4cc., sand 3/4%, solids 8%.

12-28 19th Day. Directionally drilled 12 1/4" hole from 5,451' to 5,714' with bit #23 and to 5,929' with bit #24.

Mud wt. 72#, Vis 42 sec., W.L. 7.0cc., sand 1/2% solids 8%.

12-29 20th Day. Dyna-drilled 12 1/4" hole from 5,929' to 5,953' with bit #25 and to 5,955' with bit #26 on Dyna-drill #3 guided by Eastman "DOT" tool.

Mud wt. 72.5#, Vis. 42 sec., W.L. 7.7cc., sand 1/2%, solids 8%.

12-30 21st Day. Dyna-drilled from 5,955' to 5,977' with bit #26 and to 6,002' with bit #27 on Dyna-drill #3 guided by Eastman "DOT" tool.

Mud wt. 72.5#, Vis. 47 sec., W.L. 7.4cc., sand 1/2%, solids 8%.

12-31 22nd Day. Directionally drilled 12 1/4" hole from 6,002' to 6,435' with bit #28.

Mud wt. 72.5#, Vis. 44 sec., W.L. 6.4cc., sand 1/2%, solids 8%.

1-1 Histor[illegible]of Well Report for Porter #42-[illegible] Aliso Canyon

1-1 23rd Day. Directionally drilled 12 1/4" hole from 6,435' to 6,836' with bit #29.

Mud Wt. 72#, Vis. 36 sec.

1-2 24th Day. Directionally drilled 12 1/4" hole from 6,836' to 6,991' with bit #30. While running directional survey at 6,991', piano wire survey line parted leaving over 6,000' of wire inside drill pipe. Started to pull drill pipe and main drive in gear box failed.

Mud wt. 72#, Vis. 40 sec., W.L. 6.6cc., sand 1/2%, solids 8%.

1-3 25th Day. Repairing rig

1-4 26th Day. Repairing rig.

1-5 27th Day. Repairing rig.

1-6 28th Day. Repairing rig.

1-7 29th Day. Finished repairing rig at 9:00 p.m.. Circulated through stuck pipe at 6,950' for 2 hours. Spotted 3 barrels of Baroid "XMDL" and "Torque Trim" around bottom hole drilling assembly.

Mud wt. 72#, Vis. 46 sec., W.L. 8.6cc., sand 1/2%, solids 9%.

1-8 30th Day. Worked stuck pipe. Pumped 140 bbls of oil down drill pipe and displaced with 525 cu.ft. of drilling fluid. Top of oil at 5,750'. Rigged up Archer Reed to retrieve .092" wireline from inside 4 1/2" drill pipe. Retrieved only 300' and could not find wireline again. At 9:00 p.m., pumped 634 cu.ft. of drilling fluid down drill pipe and moved top of oil to 4,400', bottom of oil at 5,750'. Rigged up Dia-Log and ran spear which became stuck at 6,730'.

1-9 31st Day. Continued jarring on spear and pulled out of rope socket. Ran overshot and latched onto spear. Pulled out of rope socket and left fishing tools inside drill collars. Ran free point but, could not go past 3,920'. Retrieved approximately 3,000' of .092" wireline. Ran overshot and could not pull tools out. Top of wireline fish at 6,855'. Ran free point. 4 1/2" pipe stuck at 5,724'. Circulated and conditioned mud.

Mud wt. 71#, Vis. 40 sec., W.L. 6.4cc., sand 1/2%, solids 9%, oil 6%.

1-10 32nd Day. Circulated and conditioned mud. Spotted 70 bbls of oil around drill collars and heavy wall drill pipe. Ran a free point, and backed off drill pipe at 5,240'. Ran jars and bumper sub and a screw in sub on bottom of six drill collars.

1-11 33rd Day. Jarred on fish and ran Dia-Log "freepoint". Pipe free at 5,955' and backed off at 5,933' wireline measurment. Recovered 692' of fish. Made up and ran new fishing tools. Found top of fish at 5,841' drillers depth.

1979 History of Well Report for Porter #42-B, Aliso Canyon

1-12 34th Day. Jarred on fish and ran a "feeler" on Dia-Log freepoint. Would not go past 5,955'. Ran an "Impression" block on Dia-Log wireline, results, inconclusive. Ran a wireline spud bit and drilled on obstruction to 6,208'. Ran a Cavins wireline junk bailer to 6,208'. First run okay. Second run bailer came off sinker bars. Chased bailer to top of other fish inside 4 1/2" drill pipe. Top of inside fish now at 6,835'.

1-13 35th Day. Ran Dia-Log wireline "freepoint" and backed off at 6,264'. Recovered 336' of heavy wall drill pipe. Ran back in and jarred on fish now at 6,264'.

1-14 36th Day. Jarred on fish and had a slight movement at 2:00 a.m. Fish came free at 4:00 a.m. Pulled out of hole with fish. Made up drilling assembly.

1-15 37th Day. Ran bit #31. Circulated and conditioned mud at 6,000'. Reamed from 6,000' to 6,991'. Circulated and conditioned mud at 6,991'. Directionally drilled 12 1/4" hole from 6,991' to 7,156' with bit #31.

Mud wt. 70#, Vis. 46 sec., W.L. 5.8cc., sand 1/2%, solids 8%.

1-16 38th Day. Wiped hole four stands at 7,156'. Directionally drilled 12 1/4" hole from 7,156' to 7,185' with bit #31, and to 7,344' with bit #32. Wiped hole four stands at 7,265'.

Mud wt. 72#, Vis. 48 sec., W.L. 5.6cc., sand 1/2%, solids 9%.

1-17 39th Day. Directionally drilled 12 1/4" hole from 7,344' to 7,575' with bit #33.

Mud wt. 72#, Vis. 47 sec., W.L. 5.8cc., sand 1/2%, solids 9%

1-18 40th Day. Circulated well clean, pulled out with bit #33 to 1,000', ran in to 7,575'. Circulated and conditioned drilling fluid. Pulled out. Ran Welex Induction Log and Caliper from 7,575' to 1,000'.

Mud wt. 72#, Vis. 44 sec., W.L. 5.8cc., sand 1/2%, solids 9%.

1-19 41st Day. Directionally drilled 12 1/4" hole from 7,575' to 7,610' with bit #33. Circulated and conditioned mud at 7,610', and pulled up to 6,780' and ran back to 7,610'. Circulated hole clean (no fill). Pulled out and ran Welex Induction and Caliper Log from 7,610' to 5,500'.

1-20 42nd Day. Circulated and conditioned mud at 7,610'. Wiped hole from 7,610' to 6,780'. Pulled out and laid down all 12 1/4" tools. Changed rams to 8 5/8" and pulled bit guide. Rigged up and ran 8 5/8" casing as follows: 86 joints of N-80 36# buttress with the first 24 joints sand blasted with two centralizers and three scratcher clusters on bottom three joints and centralizers on every other joint for 989.63', B & W shoe on bottom and float collar on top of the first three joints which were Baker locked.

Mud wt. 72#, Vis. 48 sec., W.L. 5.8cc., sand 1/2%, solids 9%.

1979

1-21 43rd Day. Finished running 8 5/8" casing to 7,610'. Circulated and reciprocated pipe. Added inhibitor while circulating. Cemented 8 5/8" casing shoe at 7,610' as follows: 500 cu.ft. of "CWT" wash followed with 1,200 cu.ft. of 1.1 class "G" cement treated with "Litepoz 7" premixed with 1.0% "D-65" and 0.5% "D-60", followed with 350 sacks of class "G" cement with 0.75% "D-65" and 0.5% "D-60", followed with 250 cu.ft. of "Self Stress" with 0.5% "D-65" amd 0.2% "D-108". Used top and bottom plugs. Reciprocated pipe while displacing cement. Cement in Place at 2:33 p.m. Set slips with hook load of 270,000# and cut off 8 5/8" casing. Installed 8" 5,000# seal flange and tubing head. Reinstalled BOPE.

1-22 44th Day. Tested blank rams, choke manifold and Kelly cock to 4,000 psi with water and nitrogen for 20 minutes, tested ok.

1-23 45th Day. Pressure tested BOPE, pipe rams to 4,000 psi for 20 minutes with water and nitrogen. Tested "GK" Hydril to 2,700 psi with water and nitrogen and all tested ok. Drilled out cement from 7,401' to 7,590' with bit #34. Circulated and pulled out of well to run Cement Bond Log.

Mud wt. 72#, Vis. 40 sec., W.L. 8.6cc., sand trace, solids 8%.

1-24 46th Day. Ran Welex Neutron Cement Bond Log, and recorded from 7,594' to 3,110'. Ran in well with casing scraper and displaced clay-water drilling fluid with 72# "HEC" brine-polymer completion fluid. Shot four 1/2" holes at 7,500' and pressure tested holes. Had 600 psi build up then pressure fell back to zero. Pumped away 50 cu.ft. per minute.

Mud wt. 72#, Vis. 38 sec., W.L. 9.0cc., solids 8%.

1-25 47th Day. Ran in well with Halliburton "E-Z" drill retainer to 7,512' and spotted 100 cu.ft. of water. Pulled up to 7,392' and set packer. Obtained breakdown of 1 cu.ft. per minute at 2,500 psi. Squeezed away 40 cu.ft. of 13% acid (10% HCL and 3% HF) with a final breakdown of 10 cu.ft. per minute at 1,800 psi. Squeezed away 89 cu.ft. of class "G" cement with 0.75% "D-65". Final squeeze pressure was 2,500 psi.

1-26 48th Day. Ran in well and drilled out retainer and cement from 7,390' to 7,463' with bit #35 and to 7,478' with bit #36.

Mud wt. 72#, Vis. 41 sec., W.L. 9.2cc., solids 9%, sand trace.

1-27 49th Day. Drilled on "E-Z" drill retainer and cement from 7,493' to 7,520' with bit #37. Pressure tested shot holes from 7,500' to 7,501' at 2,500 psi for 20 minutes, OK. Shot four 1/2" holes; 7,498' - 7,49 ' Pressure tested holes on two tests to 2,500 psi for 20 minutes, each with Dowell cementing truck. Ran WSO with Lynes test tools. Packer set at 7,434' with tail to 7,452'. Opened tool at 11:00 p.m. Had a two minute blow then dead for balance of one hour test, Witnessed and approved by D.O.G. Had 20' fluid rise. Initial pressure 50 psi, final flow pressure, 50 psi. Hydrostatic pressure 3,700 psi.

1979 History of Well Report for Porter #42-B, Oso Canyon

1-28 50th Day. Ran in and drilled out remaining cement and cement guide shoe at 7,610'. Drilled 7 5/8" hole from 7,610' to 7,712' with bit #38.

Mud wt. 73#, Vis. 39 sec., W.L. 8.8cc., solids 9%.

1-29 51st Day. Drilled 7 5/8" hole from 7,712' to 7,763' with bit #39 and to 7,799' with bit #40.

Mud wt. 72#, Vis. 41 sec., W.L. 8.6cc., solids 9%.

1-30 52nd Day. Drilled 7 5/8" hole from 7,799' to 7,816' T.D. with bit #40. Ran "IES" Log and Density Neutron Log. Opened 7 5/8" hole to 15" from 7,610' to 7,630' with hole opener #1.

Mud wt. 72#, Vis 38 sec., W. L. 9.6cc., solids 9%.

1-31 53rd Day. Opened 7 5/8" hole to 15" from 7,630' to 7,642' with hole opener #2, and to 7,655' with hole opener #3.

Mud wt. 72#, Vis. 43 sec., W.L. 9.2cc., solids 9%.

2-1 54th Day. Opened 7 5/8" hole to 15" from 7,655' to 7,704' with hole opener #3, and to 7,747' with hole opener #4.

Mud wt. 72#, Vis. 40 sec., W.L. 9.2cc., solids8%.

2-2 55th Day. Opened 7 5/8" hole to 15" from 7,747' to 7,764' with hole opener #5 and to 7,789' with hole opener #6.

Mud wt. 72#, Vis. 45 sec., W.L. 9.2cc., solids 8%.

2-3 56th Day. Opened 7 5/8" hole to 15" from 7,789' to 7,798' with hole opener #7. Made a clean out run and cleaned out fill from 7,798' to 7,816' with rerun 7 5/8" bit #38.

Mud wt. 72#, Vis. 42 sec., W.L. 9.4cc., solids 8%.

2-4 57th Day. Ran in hole with hole opener #8 and could not get through casing shoe at 7,610'. Ran 7 5/8" bit #RR38 and cleaned out through 8 5/8" casing shoe. Ran hole opener #8, tool would not open at 7,798'. Pulled out for new hole opener.

Mud wt. 72#, Vis. 45 sec., W.L. 9.4cc., solids 8%.

2-5 58th Day. Opened 7 5/8" hole to 15" from 7,798' to 7,816' with hole opener #9. Ran a Sharp 15" hole opener #10 and gage reamed from 7,610' to 7,816'. Ran Dresser Atlas Caliper Log with bore hole volume integretor and recorded from 7,816' to 7,560'.

1979 History of Well Report for Porter #42-B, Aliso Canyon

2-6 59th Day. Ran 7 5/8" bit to 7,816'. Pulled up to 8 5/8" casing shoe and cleaned mud tanks. Changed over completion fluid to 63# filtered polymer-brine gravel pack fluid. Ran 10 joints of 5 1/2" 20# liner as follows: 1 blank 10' pup joint with a bull plug on bottom followed by 5 joints of wire wrap for 218.68' followed by 2 blank joints for 83.25' followed by 1 wire wrap for 41.50' and 10' pup joint on top with a 7' Burns Liner Hanger with lead seal for a total of 367'. Liner equipped with five 5 1/2" x 15" centralizers and the 2 blanks with weld on centralizers. Hung liner 5' off bottom. Top of liner at 7,443' and bottom at 7,811'.

Mud wt. 63#, Vis. 38 sec., W.L. 10.6cc., solids 4%.

2-7 60th Day. Tested port collar to 1,000 psi. Opened port collar and circulated before gravel packing. Gravel packed with 30 sacks and pressured up to 900 psi. Reverse circulated out approximately 10 sacks of gravel. Gravel packed at 15 to 20 sacks per hour. Gravel packed liner with 272 sacks of 20 x 40 Monterey gravel and had a pack off of 1,000 psi. Reverse circulated and tested port ~~collar to~~ 900 psi.

Mud wt. 63#, Vis. 36 sec., W.L. 10.4cc., solids 4%.

2-8 61st Day. Pulled out gravel packing tools and ran in with wash tool and washed liner. Laid down wash tool and ran gravel packing tool. Had a pack off of 1,000 psi, unable to displace more gravel. Ran Dresser Atlas "photon" log.

2-9 62nd Day. Finished running Dresser Atlas "photon" log. Ran A Baker "Retrieva-D" packer on Welex wireline and set at 7,400'. Laid down 4 1/2" drill pipe and 6" drill collars.

2-10 63rd Day. Unloaded and measured 3 1/2" tubing. Changed 4 1/2" pipe rams in ~~BOPE to 3 1/2". Changed collars on 30 joints of 3 1/2" N-80 tubing.~~ Picked up and ran tubing with 2 seals and locator sub. Set 20,000# on 8 5/8" 36# packer at 7,403'. Closed pipe rams and tested packer to 1,500 psi for 20 minutes, test was ok.

2-11 64th Day. Hydrotested tubing to 5,000 psi. Spaced out and landed 65 joints of 3 1/2" N-80 EUE tubing and 175 joints of J-55, 3 1/2" tubing and an 8' J-55 pup joint on top. Landed with 20,000# on packer at 7,403', tubing measurments and 7,400', wireline measurments. Installed xmas tree and tested to 5,000 psi for 20 minutes. Displaced brine-polymer completion fluid with 450 bbls of waste lease brine. Retightened all xmas tree nuts. Released rig at 11:59 p.m., 2-11-79.

Ex. I – 61

Response to Data Request

Blade Response to SoCalGas Data Request

Prepared for:
Messrs. A. Patel and G. Healy

Purpose:
Blade response to the SoCalGas Data Request December 12, 2019.

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www.blade-energy.com

Date:
Jan. 9, 2020

Version:
1

Project Number:
N/A

Blade Energy Partners Limited and its affiliates (Blade) provide our services subject to our General Terms and Conditions (GTC) in effect at time of service, unless a GTC provision is expressly superseded in a separate agreement made with Blade. Blade's work product is based on information sources which we believe to be reliable, including information that was publicly available and that was provided by our client; but Blade does not guarantee the accuracy or completeness of the information provided. All statements are the opinions of Blade based on generally-accepted and reasonable practices in the industry. Our clients remain fully responsible for all clients' decisions, actions and omissions, whether based upon Blade's work product or not; and Blade's liability solely extends to the cost of its work product.

Version Record

Version	Issue Date	Issued As/ Type of Version	Author	Checked By	Project Leader
1	Jan. 9, 2020	Final	Blade	Blade	RMK

Version History

Version	Date	Description of Change

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1 Background

Southern California Gas Company (SoCalGas) issued a data request to Blade Energy Partners (Blade) on December 12, 2019.

Blade reviewed the data request and prepared responses to each part of the request. The SoCalGas questions are included verbatim followed by the Blade responses in Section 2.

2 Questions and Responses

2.1 Question 1

With regards to YOUR statement in the BLADE REPORT, at pp. 5 and 238, that SoCalGas lacked an "understanding of the groundwater depths relative to the surface casing shoe and production casing…" at SS 25, please respond to the following questions:

2.2 Question 1.a.

Identify and describe any and all INDUSTRY STANDARD(S) that YOU considered, evaluated or assessed in connection with the above statement.

2.2.1 Response 1.a.

Blade did not consider, evaluate or assess any INDUSTRY STANDARD(S) regarding "The lack of understanding of groundwater depths . . ." statement referenced in the root cause analysis (RCA) report. The above-mentioned statement is Blade's technical conclusion based on the observations and data collected, reviewed and evaluated during the RCA investigation, as discussed in more detail below.

Blade conducted a technical RCA to determine the cause of the 7 in. production casing failure in well SS-25. External corrosion on the 7 in. production casing was identified as a direct root cause of the SS-25 casing failure as discussed in the RCA report. Groundwater is discussed in the Blade report in Section 2.7. An aqueous environment had to be present in the 7 in. × 11 3/4 in. annulus for the microbial corrosion to occur. Groundwater is the only logical explanation that could allow the corrosion to take place. The pH of the drilling fluid left behind the casing would have been too high to allow corrosion. Over time, the residual drilling fluid, which was left in the annulus after the production casing was cemented, was replaced by groundwater. Groundwater also caused the external corrosion in the 11 3/4 in. surface casing, resulting in numerous holes above 400 ft. Casing integrity depends on maintaining sufficient casing wall thickness to withstand the pressure loads on the casing. Corrosion reduced casing wall thickness and therefore the casing pressure capacity.

During the RCA, Blade did not identify any pre-incident data, whether proprietary or public, that discussed the depth or characteristics of groundwater in the area. Borehole TH-1/RBMW-1 was drilled to a depth of 1,110 ft at a location approximately 600 ft from SS-25. Blade requested this borehole to locate possible water sources and specified an evaluation program to assess formations and identify any associated water sources as part of the RCA. Groundwater was located and sampled in TH-1/RBMW-1 between 900 – 1,000 ft. (A shallower adjacent well TH-2/RBMW-2 located and sampled groundwater between 340 – 440 ft.) The TH-1/RBMW-1 groundwater depth is deeper than the 800 ft value typically included in Aliso Canyon well NOIs as the base of freshwater.

2.3 Question 1.b.

Produce any and all DOCUMENTS related to any INDUSTRY STANDARDS identified in response to Request 1(a).

2.3.1 Response 1.b.

No Industry standards were utilized to assess the "The lack of understanding of groundwater depths . . ." statement referenced in the RCA report.

2.4 Question 1.c.

Identify any and all LAWS that YOU considered, evaluated or assessed in connection with the above statement.

2.4.1 Response 1.c.

Blade did not consider, evaluate or assess any LAWS regarding "The lack of understanding of groundwater depths . . ." statement referenced in the RCA report.

2.5 Question 1.d.

For each LAW that YOU evaluated in preparing the BLADE REPORT identified in response to Request 1(c), state YOUR understanding as to whether SoCalGas complied with the LAW.

2.5.1 Response 1.d.

Blade did not consider, evaluate or assess any LAWS regarding "The lack of understanding of groundwater depths . . ." statement referenced in the RCA report.

3 Nomenclature

3.1 Abbreviations and Acronyms

Term	Definition
BFW	Base of Freshwater
Blade	Blade Energy Partners
DOGGR	Division of Gas, Oil, and Geothermal Resources
NOI	Notice of Intent
RCA	Root Cause Analysis
SoCalGas	Southern California Gas Company

Ex. I – 62

Due to the large file size, this exhibit is an excerpt. The native file of this document is available upon request.

Company: Southern California Gas Company (U 904 G)
Proceeding: 2016 General Rate Case
Application: A.14-11-XXX
Exhibit: SCG-06

SOCALGAS

DIRECT TESTIMONY OF PHILLIP E. BAKER

UNDERGROUND STORAGE

November, 2014

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Southern California Gas Company
A Sempra Energy utility®

Table PEB-3 below further summarizes the descriptive characteristics of all four storage fields.

Table PEB-3
Southern California Gas Company
Descriptive Statistics of Storage Fields

Descriptive Statistic	Aliso Canyon	La Goleta	Honor Rancho	Playa del Rey	Total All Fields
Year Field Placed in Service	1973	1941	1975	1942	-
Injection/Withdrawal/Observation Wells (number)	115	20	40	54	229
Gas Compressor Units (number)	8	8	5	3	24
Compression Horsepower (bhp)	42,000	5,700	27,500	6,000	81,000
Maximum Reservoir Pressure (psig)	3,600	2,050	4,400	1,700	-
Working Gas (Bcf)	86.2	21.5	26.0	2.4	136.1
Maximum Withdrawal Rate (MMcfd)	1,860	420	1,000	400	3,760
Maximum Injection Rate (MMcfd)	600	140	300	75	1,115
Maximum Well Depth (feet)	10,691	6,912	13,300	6,575	-
Minimum Well Depth (feet)	6,997	4,247	9,165	6,049	-
Average Well Depth (feet)	8,146	4,886	9,959	6,339	-

C. Risk Management Practices in Storage

The risk policy witnesses, Diana Day (Exhibit SCG-02) and Doug Schneider (Exhibit SCG-03), describe how risks are assessed and factored into cost decisions on an enterprise-wide basis. Several of my costs address safety risks associated with the storage system. Most specifically, I propose to establish a new SIMP, described and discussed below in the O&M and Capital cost sections, to mitigate safety-related risks.

While we have historically managed risk at our storage facilities by relying on more traditional monitoring activities and identification of potential component failures, we believe that it is critical that we adopt a more proactive and in-depth approach. Historically, safety and risk considerations for wells and their associated valves and piping components have not been addressed in past rate cases to the same extent that distribution and transmission facilities have been under the Distribution and Transmission integrity management programs. As a prudent storage operator, SoCalGas proposes to manage and approach the integrity of its storage well assets, which all fall under the jurisdiction of the California Department of Oil, Gas and Geothermal Resources (DOGGR), in a manner consistent with the approach adopted for distribution and transmission systems. Risk management activities, processes, and procedures

for well integrity should have a focus similar to those employed under the Company's pipeline risk mitigation programs.

Accordingly, in this rate case, we propose to establish a highly proactive approach to evaluating and managing risks associated with wells in our storage system through a new SIMP, modeled after the successes of our pipeline integrity management programs (TIMP and DIMP). Through the implementation of the SIMP, better storage well system data will be collected, maintained and modeled to identify the top risks throughout Storage. Comprehensive plans to mitigate those risks will be developed and implemented.

1. Risk Assessment

Currently, risk assessment of our storage system is of a qualitative nature and is based on our long experience in operating and managing SoCalGas' storage facilities. During routine system assessments, we monitor the condition of our assets and consider the risks they may pose on safety, reliability, and the environment.

The future of risk assessment for our storage system is moving towards a more robust and quantitative approach that will help us capture more information on the condition of our storage wells and develop models that will assist in prioritizing risk mitigation activities. The details of this new risk assessment are captured in further sections of my testimony describing the SIMP.

2. Risk Mitigation Alternatives Evaluation

Well risk mitigation is evaluated on a case-by-case basis. Whenever a well may pose a safety risk, we act immediately to address the problem. Alternatives, such as plugging and abandoning the well, versus a major repair or well replacement, are evaluated based on conditions, including the age of the well, prior repair or maintenance history, performance during withdrawal or injection periods, and surface considerations, such as susceptibility to landslides. These various conditions, and their associated costs, are evaluated to determine the safest, most cost-effective mitigation option. Another consideration that may influence repair decisions is the age and condition of certain well components that may have become obsolete and are no longer supported by the original equipment manufacturer and cannot be readily replaced or maintained.

At a very high level, alternatives to mitigate risks posed by deteriorating, aging, obsolete or failed storage equipment include:

- Replacement of equipment / storage wells
- Overhaul of equipment / storage wells

- Repair of equipment / storage wells
- Abandonment of a storage well / equipment
- Installation of additional equipment

3. Risk Reduction Benefits

The proposed mitigation activities are expected to address safety, reliability and environmental risks by either maintaining a certain acceptable level of control over those risks, or by further reducing the potential impacts of the risks. While there are no current means to provide a quantitative risk reduction forecast, it is my belief that the proposed mitigation activities will greatly assist in controlling and reducing the risks in our storage system.

In addition to establishing a more quantitative risk analysis of our storage wells as discussed below, the SIMP will result in a more effective prioritization of required capital expenditures that address risks that impact safety, reliability and the environment.

4. Integration of Risk Mitigation Actions and Investment Prioritization

The implementation of the proposed SIMP will establish an integrated risk management and investment prioritization process for storage management at SoCalGas. Storage wells are an integral gas delivery component, and an unanticipated safety concern could interrupt access to the working gas asset and potentially lead to a complete shutdown of a storage field.

Models to be developed from captured well data will evaluate threats and risks that exist in our storage system. This will allow for a prioritization of those storage well threats, based on their location, age, condition and other factors, thereby establishing a robust methodology for prioritizing storage management investments.

5. Investment Included in Request to Support Risk Mitigation

Investments related to the SIMP are necessary to establish a risk management program. Future mitigation activities that will result from the implementation of the SIMP will be risk-driven and will address identified and prioritized risks. SoCalGas forecasts $5.676 million annually in O&M and $24.272 million annually in capital costs for the implementation of the SIMP. It is anticipated that the SIMP will last for six years, the estimated length of time required to inspect all of the wells and mitigate any identified conditions. After this six-year period, when the program is complete, future inspection and mitigation costs will be addressed through routine operations.

D. Support To/From Other Witnesses

In addition to sponsoring my own organization's costs, I also provide sponsorship of the New Environmental Regulatory Balancing Account (NERBA) cost forecast for the reporting requirements under Subpart W for Gas Engineering, Gas Transmission and Underground Storage for witnesses Raymond Stanford (Exhibit SCG-07), John Dagg (Exhibit SCG-05), and myself. The costs associated with Subpart W reporting requirements are illustrated in the cost detail in section II.C of my testimony. Policy testimony in support of NERBA and storm water regulations is provided by Environmental Services witness Jill Tracy (Exhibit SCG-17).

II. NON-SHARED COSTS

A. Introduction

Table PEB-4 below summarizes the total non-shared O&M forecasts for the listed cost categories.

Table PEB-4
Southern California Gas Company
Non-Shared O&M Summary of Costs

UNDERGROUND STORAGE	Thousands of 2013 Dollars		
Categories of Management	**2013 Adjusted Recorded**	**TY2016 Estimated**	**Change**
Underground Storage – Routine	$30,681	$34,101	$3,420
New Environmental Regulatory Balancing Account (NERBA) (Existing Balancing Account)	$314	$404	$90
Storage Integrity Management Program (Proposed New Balancing Account)	$0	$5,676	$5,676
Total	**$30,995**	**$40,181**	**$9,186**

B. Underground Storage – Routine O&M

Table PEB-05 below summarizes the non-shared O&M forecasts for routine storage operations.

Ex. I – 63

Due to the large file size, this exhibit is an excerpt. The native file of this document is available upon request.

1 SUPERIOR COURT OF THE STATE OF CALIFORNIA
2 COUNTY OF LOS ANGELES, CENTRAL DISTRICT
3
4 COORDINATION PROCEEDING) JCCP No. 4861
SPECIAL TITLE (Rule 3.550))
5)
)
6 SOUTHERN CALIFORNIA GAS LEAK) Hon.
CASES) Carolyn B. Kuhl
7) Department SS12
_____)
8)
THIS DOCUMENT RELATES TO:)
9)
All Actions.)
10 _____)
11
__ __ __
12 Wednesday, November 20, 2019
__ __ __
13
14 CONFIDENTIAL
SUBJECT TO FURTHER CONFIDENTIALITY REVIEW
15
16
17 Videotaped Deposition of RAVI M.
KRISHNAMURTHY, Ph.D., VOLUME 1, held at
18 Bradley Arant Boult Cummings LLP, 600 Travis,
Suite 4800, Houston, Texas, commencing at
19 9:12 a.m. on the above date, before Susan
Perry Miller, Registered Diplomate Reporter,
20 Certified Realtime Reporter, Certified
Realtime Captioner, and Notary Public.
21
22
__ __ __
23
GOLKOW LITIGATION SERVICES
24 877.370.3377 ph | 917.591.5672 fax
deps@golkow.com
25

asked them for information regarding longitudinal or circumferential through-wall defects?

A. Basically we were after other wells that may have had similar failures as SS-25. That's really all we were after.

Q. And were you after information that SoCalGas had regarding those types of casing defects prior to the SS-25 blowout?

A. Prior or post? Prior, we were looking at actual data. We couldn't find any. But we recognized the SIMP program was pretty intense and there were a lot of other casings being pulled. So that was what we were after.

Q. In the response to that question number 2 dated March 23rd, 2018, according to page 26343, SoCalGas provided a list of wells, and then on page 26344 there was an amended response dated March 22nd, 2019, and they included some revised information.

Do you see that?

A. Yes.

Q. And did you review the well

CERTIFICATE

I, SUSAN PERRY MILLER, Registered Diplomate Reporter, Certified Realtime Reporter, Certified Court Reporter and Notary Public, do hereby certify that prior to the commencement of the examination, RAVI M. KRISHNAMURTHY, Ph.D. was duly sworn by me to testify to the truth, the whole truth and nothing but the truth;

That signature of the witness was reserved by the witness or other party before the conclusion of the deposition;

That the foregoing is a verbatim transcript of the testimony as taken stenographically by and before me at the time, place and on the date hereinbefore set forth, to the best of my ability.

I DO FURTHER CERTIFY that I am neither a relative nor employee nor attorney nor counsel of any of the parties to this action, and that I am neither a relative nor employee of such attorney or counsel, and that I am not financially interested in the action.

Susan Perry Miller
CSR-TX, CCR-LA, CSR-CA-13648
Registered Diplomate Reporter
Certified Realtime Reporter
Certified Realtime Captioner
NCRA Realtime Systems Administrator
Notary Public, State of Texas
My Commission Expires 03/30/2020

Dated: 4th day of December, 2019

Ex. I – 64

SOUTHERN CALIFORNIA GAS COMPANY

CPUC-SAFETY AND ENFORCEMENT DIVISION DATA REQUEST DATED FEBRUARY 8, 2016

Question 1:

List of transmission lines and high pressure supply lines within 20 miles of Aliso Canyon Storage Field

Response 1:

CONFIDENTIAL: Submitted Under the Provisions of General Order 66-C and Section 583 of the Public Utilities Code

Enclosed is a list of transmission line pipe and high pressure supply line pipe within 20 miles of Aliso Canyon:

Response1_CPUC_DR_02.08.2016.pdf

For reference, a (high-level) map of the 20 mile radius is enclosed:

Response1A_CPUC_DR_02.08.2016.pdf

Note: Some of the pipelines listed above are short in length and may not be visible on a map depicting a 20 mile radius.

Also, the attached list reflects our current database. While we have attempted to make this list as accurate as possible, it may contain some short segments that are pending reclassification as non-line pipe.

Question 2:

Which of these pipelines had Risk and Integrity Management Assessments

SOUTHERN CALIFORNIA GAS COMPANY

CPUC-SAFETY AND ENFORCEMENT DIVISION DATA REQUEST DATED FEBRUARY 8, 2016

Response 2:

CONFIDENTIAL: Submitted Under the Provisions of General Order 66-C and Section 583 of the Public Utilities Code

Per a (telephone) follow-up conversation between Kris Keas and Matt Epuna on February 10, 2016 enclosed is a list of the pipelines that have had a Transmission Integrity Management Assessment performed:

Response2_CPUC_DR_02.08.2016.pdf

In addition to these TIMP assessments, transmission and distribution pipelines are also inspected and maintained through a comprehensive maintenance program. Some of these maintenance activities include, but are not limited to: leak survey, pipeline patrol, valve inspection, cathodic protection, and other activities as prescribed by state and federal safety regulations.

Question 3:

Assessment methods/ mile(s)

Response 3:

See Response 2.

Question 4:

Date(s) of assessments

Response 4:

See Response 2.

Question 5:

Anomalies noted

SOUTHERN CALIFORNIA GAS COMPANY

CPUC-SAFETY AND ENFORCEMENT DIVISION DATA REQUEST DATED FEBRUARY 8, 2016

Response 5:

CONFIDENTIAL: Submitted Under the Provisions of General Order 66-C and Section 583 of the Public Utilities Code

The enclosed file contains the conditions (refer to 49 CFR 192.933), remediation methods and remediation dates for pipelines within 20 miles from Aliso Canyon:

Response5_CPUC_DR_02.08.2016.pdf

Question 6:

Remediation and methods, if any

Response 6:

See Response 5.

Question 7:

Dates of remediation

Response 7:

See Response 5.

Ex. I – 65

REUTERS

campaign to slow coronavirus spread
9 MINUTES AGO

shuts borders to foreign nationals
16 MINUTES AGO

U.S. LEGAL NEWS
FEBRUARY 5, 2020 / 11:07 AM / A MONTH AGO

Chesapeake Energy, others sued for $1 million in fatal Texas oil-well blast

Liz Hampton

(Reuters) - Chesapeake Energy Corp and three oilfield service firms were sued by the daughter of a worker who suffered fatal injuries when a Texas oil well exploded in flames last month.

The wrongful death suit seeks at least $1 million from Chesapeake Energy, Forbes Energy Services, Eagle Pressure Control and Halliburton Co. It was filed this week in Harris County District Court by Madison Hendrix, whose father, Brad Hendrix, died in a hospital days after the blast.

Hendrix alleged that Chesapeake, the well owner, and the oilfield service companies were negligent, failed to provide a safe work environment or adequate medical care to the workers.

Chesapeake declined to comment and Eagle Pressure Control did not immediately respond to a request for comment. Forbes Energy Services said it was “beyond saddened that three

NOW READING Chesapeake Energy, others sued for $1 million in fatal Texas oil-well blast

Trump and U.S. states escalate campaign to slow coronavirus spread
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In bid to slow coronavirus, Canada shuts borders to foreign nationals
16 MINUTES AGO

Halliburton said it was not performing any services on the rig when the well-control incident occurred. Its well-control unit, Boots & Coots, was hired to handle the post-incident well intervention work, a spokeswoman for the company said.

Brad Hendrix was a well-intervention technical adviser at Eagle Pressure Control, according to his LinkedIn profile. He was one of three workers fatally injured in the Jan. 29 explosion near Deanville, Texas.

A second Eagle Pressure Control employee, Windell Beddingfield, died on the day of the accident, according to an attorney for the family. His mother last week sought a temporary restraining order against Chesapeake to require it to preserve evidence from the blast.

A third victim, identified by local media as Brian Maldonado of San Diego, Texas, died in a hospital over the weekend. A fourth worker was airlifted to a hospital and has not been identified.

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16 MINUTES AGO

when natural gas leaked from a well during a workover operation and exploded near Deanville, about 75 miles (120 km) east off Austin.

WildHorse Resource Development Corp, which Chesapeake acquired last year, also was named in the lawsuit.

Reporting by Liz Hampton in Houston; Editing by Matthew Lewis and Peter Cooney

Our Standards: The Thomson Reuters Trust Principles.

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16 MINUTES AGO

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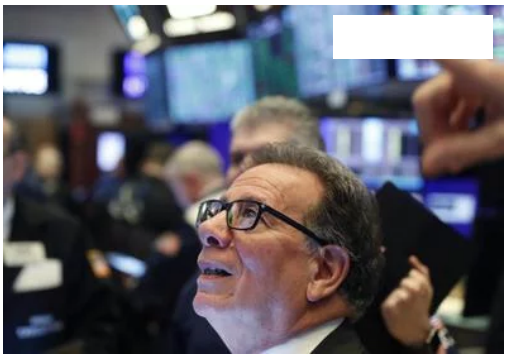

Wall Street sinks as Fed's shock cut increases worries over virus...

16 Mar

Germany tries to halt U.S. interest in firm working on coronavirus...

15 Mar

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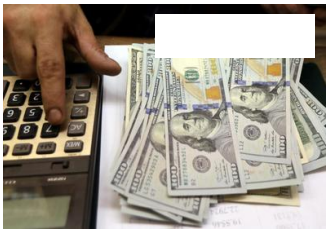

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Federal agencies probe Chesapeake well blowout that killed 3 workers in Texas

- February 5, 2020 (2020-02-05T08:29:56+00:00)

The Chesapeake well blowout and fire that has now claimed the lives of three workers in South Texas is being probed by at least two federal agencies as well as a Texas agency.

Investigators for the Occupational Safety and Health Administration and the Chemical Safety Board were in Burleson County this week at the site of a blowout that occurred Jan. 29 according to a report by the *San Antonio Business Journal.*

OSHA first appeared on site Sunday, and CSB is completing its on-site investigation this week, according to documents provided to the Business Journal by the Railroad Commission of Texas (https://www.bizjournals.com/profile/company/org_xx_302eae52a72d11e8abd612c1e58b58b2), which is also investigating the incident. In addition, the Railroad Commission document said other agencies would be on-site and off-site over the coming week, although it didn't name those agencies.

Neither OSHA nor the CSB responded to requests for further information.

One worker died immediately when natural gas in the well sparked a fire, according to initial reports. Two later died of their injuries in the hospital, with one dying over the weekend. The condition of the fourth worker injured in the blast hasn't been made known.

The well belongs to Oklahoma-based Chesapeake Energy Corp., and the workers were employed by contractors hired by Chesapeake (NYSE: CHK) to drill it. The mother of one of the victims has already filed a lawsuit against Chesapake Energy.

"We are deeply saddened to learn that a third contractor has died as a result of injuries sustained in last week's well control incident," Chesapeake spokesman Gordon Pennoyer (https://www.bizjournals.com/sanantonio/search/results?q=Gordon%20Pennoyer) said in a statement. "Our thoughts and our prayers remain with those impacted. The cause of the incident is currently under investigation."

The Chemical Safety Board also investigated the January 2018 well blowout that killed five workers near Quinton, Oklahoma. It later issued a report blaming some of the operators for the tragedy.

The CSB is a nonregulatory agency, meaning it cannot issue fines or citations. It can give recommendations to agencies such as OSHA and the U.S. Environmental Protection Agency, both of which can take enforcement actions based on such recommendations. Investigations typically take several months while OSHA must issue a citation or penalty within six months of a violation occurring, according to CSB's website.

Source: San Antonio Business Journal

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Feds To Probe Fatal Chesapeake Energy Oil Well Accident

February 4, 2020

Federal officials are stepping into an investigation of an accident at a Chesapeake Energy oil well that left three men dead and another hospitalized.

In a Monday statement, the U.S. Chemical Safety and Hazard Investigation Board announced it has deployed a team to investigate the fatal Jan. 30 accident in Burleson County that killed three workers and left one hospitalized.

Known as the CSB, the federal agency was launched in 1998 to investigate accidents and to determine the conditions and circumstances that led up to them. As part of its work, the agency identifies the cause or causes of accidents so that similar events might be prevented.

The federal investigation will run alongside ones being conducted by state and local authorities.

In a court filing, family members reported that 38-year-old Windell Beddingfield of Tyler died at the scene.

The identity of the second worker who died has not been released but family members of 25-year-old Brian Maldonado reported that the San Diego, Texas died in the hospital on Saturday.

Eleven people from Chesapeake, Fort Worth oil field service company Eagle Pressure Control and Alice oil field service company C.C. Forbes were working at the well at the time of the incident, a report from the Railroad Commission of Texas shows.

Investigators believe that an unexpected amount of natural gas entered the well and ignited. What caused the ignition remains under investigation.

Beddingfield and the second man who died worked for

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C.C. Forbes. The companies could not immediately be reached comment about the federal investigation.

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Justin Hicks

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FEATURED

One killed, three injured in well site accident

'Flash fire' incident claims life of Wyoming man

By Amy Dalrymple Forum News Service

Jun 20, 2016

The workover rig in McKenzie County where three men were injured and one was killed Saturday morning in an explosion.

Photo by Elizabeth Hackenburg

WATFORD CITY, N.D. – One worker has died and three were injured in a fire at a McKenzie County oil well site over the weekend, the Occupational Safety and Health Administration said Monday.

Crews were working on a workover rig on a well about 8 miles east of Watford City when the well ignited about 8:30 a.m. Saturday, said Eric Brooks, director of the Bismarck area OSHA office.

The owner of the well, XTO Energy, described the incident as a “flash fire.”

Johnny Stassinos, 52, Rock Springs, Wyo., died from his injuries Saturday afternoon at Trinity Hospital in Minot, the McKenzie County Sheriff’s Office said.

Daniel Montes, 28, Fruita, Colo., and Richard Maheu, 27, Rock Springs, Wyo., suffered serious burns and were in critical condition at Regions Hospital in St. Paul, the sheriff’s office said.

Justin Pyle, 30, Grand Junction, Colo., was treated and released for minor injuries from McKenzie County Heathcare Systems Hospital in Watford City, officials said.

The workers were employees of Most Wanted Well Service and SEI Well Service, said Emily Snooks, a spokeswoman for XTO, a subsidiary of Exxon Mobil Corp.

OSHA has launched an investigation and an inspector will be at the site today, Brooks said.

XTO has also formed an investigation team to determine the cause of the incident, Snooks said.

“We are greatly saddened by this tragic incident, and we express our deepest sympathy to the workers and the families of those affected,” Snooks said.

Alison Ritter, spokeswoman for the Department of Mineral Resources, said crews were working on a well that had been fracked when the well “experienced a kick of gas” on Saturday morning.

When deputies arrived on scene, the fire was out, authorities said. First-responders provided basic first aid on scene. One victim was airlifted from the scene and two were transported from the Watford City Airport, the sheriff’s office said.

A workover rig is smaller than a drilling rig and is used for well completions and maintenance.

The incident did not cause any oil or other contamination to leave the well location, according to the North Dakota Department of Health.

This is the second oil and gas fatality OSHA has investigated in North Dakota in 2016, Brooks said.

Ex. I – 69

Due to the large file size, this exhibit is an excerpt. The native file of this document is available upon request.

OIL AND GAS EXTRACTION WORKER FATALITIES 2014

NIOSH Fatalities in Oil and Gas Extraction (FOG) Database

Sophia Ridl, Kyla Retzer, and Ryan Hill

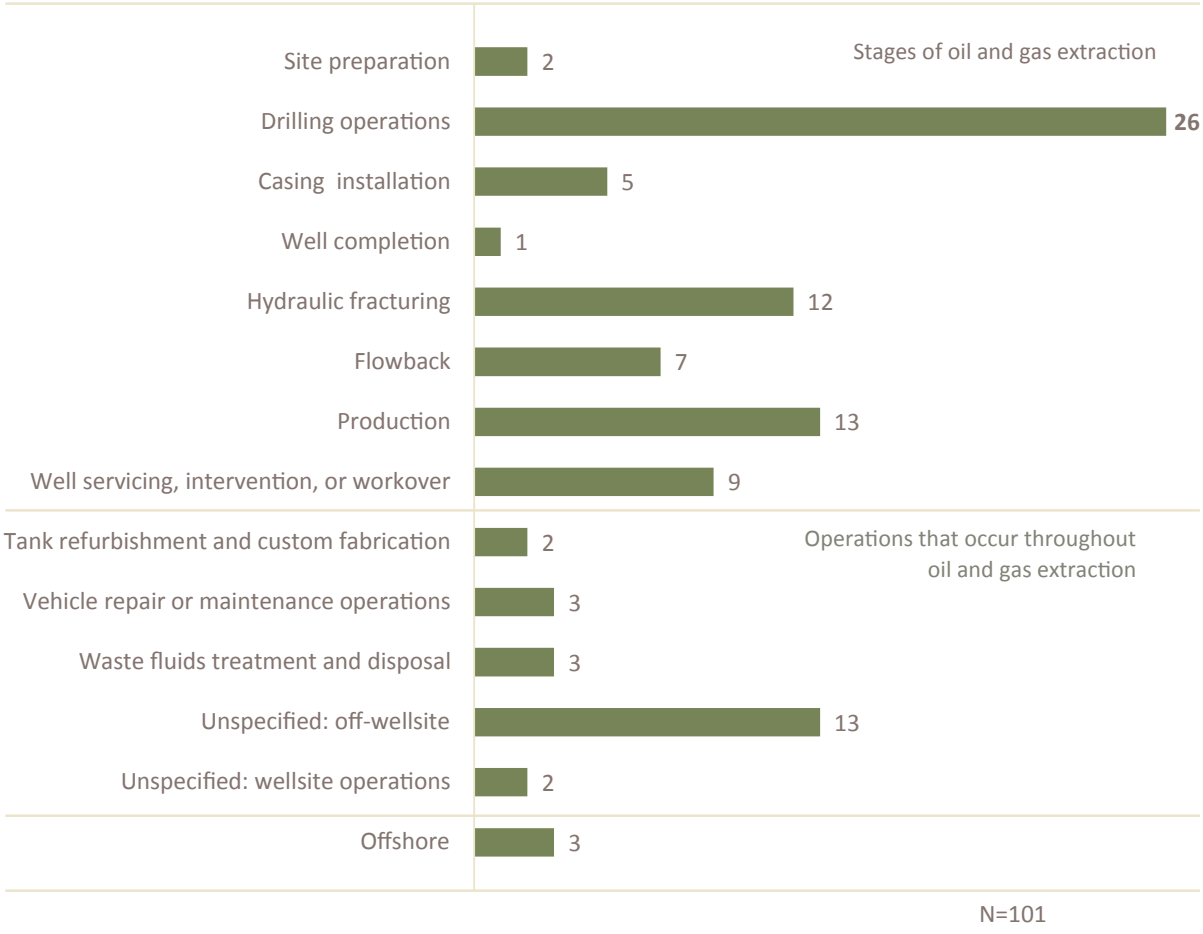
DEPARTMENT OF HEALTH AND HUMAN SERVICES
Centers for Disease Control and Prevention
National Institute for Occupational Safety and Health

OPERATION

- The operation could be determined in 75 (85%) of the 88 incidents. Where operation is unspecified, the incidents were categorized into off-wellsite and on-wellsite operations (13 incidents accounting for 15 fatalities)
- The largest number of fatalities occurred during drilling operations (26 fatalities).
- Twenty worker fatalities occurred during completions (well completion, hydraulic fracturing, and flowback).

OPERATION
Operations are distinct stages or processes in oil and gas extraction. Each incident is assigned one operation.

FATALITIES IN FOG BY OPERATION, 2014



ACTIVITIES

- Fatalities occurred during 43 different types of activities.
- Activities that were most commonly associated with fatalities included motor vehicle travel (including non-traditional commuting), material handling using a crane, forklift or winch truck, and rig or equipment repair or maintenance.

ACTIVITIES
Activities are components or steps within oil and gas extraction operations that may occur several times. Each incident is assigned as many activities as appropriate.

FATALITIES IN FOG BY ACTIVITY, 2014

HIGH FREQUENCY (8+ FATALITIES)	
ACTIVITY	# OF FATALITIES
Motor vehicle travel	18
Material handling: crane, forklift, winch truck	12
Rig or equipment repair or maintenance	11
Commuting: non-traditional	10
Make up or break out tubulars	8
Production rig activities	8
Rigging up or down	8

MODERATE FREQUENCY (4–7 FATALITIES)	
ACTIVITY	# OF FATALITIES
Tank gauging or sampling	7
Equipment install or dismantle	6
Produced and waste fluids storage	6
Wellhead or pumping unit activities	6
Making a connection	5
Separation equipment activities	5
Well control equipment activities	5
Hotwork and welding	4
Laydown or pickup tubulars	4
Pressure pumping	4
Tripping pipe in or out	4
Truck transport: crude oil hauling	4
Vacuum truck activities	4
Wellsite maintenance or construction	4

LOW FREQUENCY (1–3 FATALITIES)	
ACTIVITY	# OF FATALITIES
Downhole tool and equipment activities	3
Production monitoring	3
Running casing	3
Spotting	3
Tank cleaning or maintenance	3
Truck transport: equipment or supplies hauling	3
Coiled tubing activities	2
Drilling fluid mixing and pumping	2
Non-motor vehicle travel	2
Pulling or running rods	2
Truck transport: produced or waste water hauling	2
Truck transport: unspecified cargo	2
Well cleanout	2
Well testing and logging	2
Break or rest	1
Plug drill out	1
Production tubing installation	1
Pulling or running tubing	1
Racking back tubulars	1
Snubbing	1
Truck transport: water hauling	1
Vehicle repair or maintenance activities	1

OPERATION AND INDUSTRY GROUP

- Fatalities to servicing company workers occurred throughout most operations, with the highest number of fatalities occurring during hydraulic fracturing and production.
- Most fatalities to drilling company workers occurred during drilling operations (20 deaths). However, three employees died during casing installation and another three during flowback.
- Workers from all industry groups were killed during drilling operations.

OPERATION
Operations are distinct stages or processes in oil and gas extraction. Each incident is assigned one operation.

INDUSTRY GROUP
The industry group is based on the NAICS code of the employer. A company's NAICS code is determined by its primary business and may be different than the work being done at the time of the incident. Each fatality is assigned to one industry group.

FATALITIES IN FOG BY INDUSTRY GROUP (NAICS) AND OPERATION, 2014

OPERATION	OPERATING COMPANY (211)	DRILLING COMPANY (213111)	SERVICING COMPANY (213112)	OTHER INDUSTRY	UNKNOWN	TOTAL
Site preparation			1	1		2
Drilling operations	1	20	4		1	26
Casing installation		3	2			5
Well completion	1					1
Hydraulic fracturing	1		11			12
Flowback		3	3	1		7
Production	2		11			13
Well servicing, intervention, or workover	2		5	2		9
Tank refurbishment and custom fabrication	1		1			2
Vehicle repair or maintenance operations			2	1		3
Waste fluids treatment and disposal		1		2		3
Unspecified: off-wellsite	1		4	1	7	13
Unspecified: wellsite	1		1			2
Offshore					3	3
Total	**10**	**27**	**45**	**8**	**11**	**101**

Ex. I – 70

Due to the large file size, this exhibit is an excerpt. The native file of this document is available upon request.

Message from the Secretary of Energy

Earlier this year, Congress and the Administration worked together to establish a Federal Task Force to analyze California's Aliso Canyon natural gas leak and make recommendations on how to reduce the likelihood of future leaks from underground natural gas storage facilities across the country. While these incidents are rare, the leak at Aliso Canyon is a reminder that failures at aging natural gas storage facilities can have damaging effects on communities, the environment, and the reliability of our energy supplies.

At the same time, the Nation's 400+ natural gas storage facilities provide essential services. They deliver gas at times of high demand to heat our homes and businesses, to power American industry, and increasingly, to provide fuel for electricity generation.

The Task Force identified three principal research areas associated with natural gas storage facilities: minimizing the risk of well failures; reducing health and environmental impacts of major leak incidents; and understanding energy reliability implications. Across these areas, the Task Force has made more than 40 recommendations that identify the need for additional actions at our Nation's natural gas storage facilities to ensure their long-term safety and reliable operation.

Key recommendations of the Task Force include:

- Gas storage operators should begin a rigorous evaluation program to baseline the status of their wells, establish risk management planning and, in most cases, phase-out old wells with single-point-of-failure designs.
- Advance preparation for possible natural gas leaks and coordinated emergency response in the case of a leak can help manage and mitigate potential health and environmental impacts of leaks when they do occur.
- Power system planners and operators need to better understand the risks that potential gas storage disruptions create for the electric system.

No community should have to go through something like the Aliso Canyon leak again. The recommendations in this report outline the steps we can take to prevent such an incident in the future. Now, it is up to industry to implement these recommendations in a timely fashion, while State and Federal officials develop regulations that enhance the safety of underground storage facilities in the United States.

Ernest J. Moniz

Secretary of Energy

Message from Task Force Co-Chairs

In April, as a part of the Administration's ongoing commitment to support State and industry efforts to ensure the safe storage of natural gas, and with the support of Congress, the Department of Energy (DOE) and the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) announced the formation of an Interagency Task Force on Underground Natural Gas Storage Safety.

Two months earlier, along with the Secretary of Energy, we visited the Aliso Canyon site to review efforts to control the leak and to learn from experts and local officials about the impacts of the leak on the environment and community.

The Task Force includes premier scientists, engineers and technical experts from across the DOE complex, including five National Labs, DOT, the Environmental Protection Agency (EPA), the Department of Health and Human Services (HHS), the Department of Commerce (DOC), the Department of the Interior (DOI), the Federal Energy Regulatory Commission (FERC), and the Executive Office of the President. As a Task Force, we have held three national-level workshops and met with community members, industry representatives, environmental organizations, and State officials.

The Task Force established three working groups for research and analysis: (1) the physical integrity of wells at gas storage facilities, (2) the reliability of natural gas supplies from gas storage facilities, and (3) the public health and environmental impacts associated with the Aliso Canyon leak.

The "Well Integrity" working group was led by DOE's Office of Fossil Energy, with important contributions from four DOE National Labs—the National Energy Technology Laboratory, Lawrence Berkeley National Laboratory, Lawrence Livermore National Laboratory, Sandia National Laboratories, and PHMSA.

The "Reliability" working group was led by the Department of Energy's Office of Electricity Delivery and Energy Reliability with important contributions by DOE's Argonne National Laboratory, DOE's Energy Information Administration, and FERC.

The "Health and Environment" working group was led by the EPA and HHS's Centers for Disease Control and Prevention. DOC's National Oceanographic and Atmospheric Administration and PHMSA also contributed.

This final report is a synthesis of the three working group reports, which will be made available as separate technical appendices to the report.

PHMSA plans to initiate regulatory actions to help ensure the safety of natural gas storage facilities across the country, beginning with an Interim Final Rule due out by the end of this year. Moving forward, PHMSA will consider the recommendations of this Task Force in developing future regulation and safety standards as required by the PIPES Act of 2016 (P.L. 114-183).

Natural gas provides heat to millions of American homes and is expected to provide a third of our Nation's total electric power generation this year. As co-chairs of this Task Force, we have made it a priority to support States, industry and the American public to ensure that our infrastructure is safe. The Task Force's efforts are an important step forward as we continue to work toward protecting public health and safety and making progress in reducing greenhouse gas emissions. We offer our recognition and gratitude to all those whose hard work and thoughtful analysis are assembled here.

Franklin Orr
Under Secretary for Science and Energy

Marie Therese Dominguez
Administrator, Pipeline and Hazardous Materials Safety Administration

Executive Summary

On October 23, 2015, the largest methane leak from a natural gas storage facility in United States history was discovered by the Southern California Gas Company (SoCalGas) at well SS-25 in its Aliso Canyon Storage Field in Los Angeles County. The leak continued for nearly four months until it was permanently sealed on February 17, 2016. In the interim, residents of nearby neighborhoods experienced health symptoms consistent with exposures to odorants added to the natural gas; thousands of households were displaced; and the Governor of California declared a state of emergency for the area. Approximately 90,000 metric tons of methane was released from the well, although estimates vary and the State of California is continuing its analysis. The incident also created serious energy supply challenges for the region and prompted broader public concerns about the safety of natural gas storage facilities.

Motivated by the events at Aliso Canyon, Federal officials, including many concerned members of Congress, sought to better understand and identify opportunities to improve the overall safety and environmental impacts of our Nation's natural gas storage infrastructure. To support these efforts, the Federal Government in April 2016 formed an Interagency Task Force on Natural Gas Storage Safety. Congress codified the Task Force through the Securing America's Future Energy: Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016 (PIPES Act). Congress directed the Task Force to perform an analysis of the Aliso Canyon events and make recommendations to reduce the occurrence of similar incidents in the future. To do so, the Task Force examined three key areas: integrity of natural gas wells at storage facilities; public health and environmental effects from natural gas leaks; and vulnerability to reduced energy reliability in the case of future leaks.

Natural gas currently meets nearly 30% of U.S. energy needs, and natural gas storage facilities are essential to the functioning of a highly seasonal natural gas market. They provide quick access to large volumes of natural gas for end users during periods of high demand, such as during a cold spell in the winter or during periods of high electricity demand in the summer. The Aliso Canyon leak illustrated how the loss of a large gas storage facility can disrupt enough gas delivery service to cause major 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. Major leaks or functional disruptions elsewhere in the gas infrastructure (i.e., at pipelines, compressor stations, gas processing plants, and liquefied natural gas terminals) could have impacts similar to those of the Aliso Canyon incident, and perhaps on an even larger scale. Further, the electric power and natural gas industries have become much more interdependent in recent years, and their interdependence is expected to grow over the next decade as the U.S. becomes more reliant on gas-fired electric generation capacity.

Approximately 80% of wells in the Nation's natural gas storage fields were completed in the 1970s or earlier. They have been exposed to decades of physical and mechanical stresses and pre-date many current materials and technology standards. In addition, many of these wells were converted to gas storage from oil production and may not have piping designed for the higher overall operating pressures of natural gas. Although rare, large natural gas storage leakage events can have negative impacts on human health and communities.

Chapter 1. Gas Storage Primer

Natural Gas Storage Basics

Why is natural gas stored underground?

Natural gas is 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, the facilities can 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.[1]

How is natural gas stored?

Natural gas is injected down the wellbore and into a subsurface geological formation. As gas is injected, pressure builds within the formation. Higher reservoir pressures allow higher gas flow volume during the extraction (withdrawal) part of the storage cycle to help ensure suitable production gas flow rates.[2] Typically, vertical wells are used to inject and withdraw the gas, although horizontal wells are becoming more common.

A significant portion of the gas that is injected initially will remain in the subsurface and will not be extracted during a typical withdrawal cycle. This gas is commonly known as "base gas" or "cushion gas." It is a permanent inventory in a storage reservoir that is needed to maintain adequate pressure, minimize water being produced with the gas, and maintain delivery rates throughout the withdrawal season.

More about how natural gas storage fields work can be found in the Niska Gas Storage Industry Primer (2010) and from the Energy Information Administration's (EIA) *Basics of Underground Natural Gas Storage*.

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 415 facilities, including approximately 400 active facilities, in more than 30 States (as shown in Figure 1). Most (~80%) of the existing natural gas storage in the United States is in depleted natural gas or oil fields that are located close to consumption centers.

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[1]U.S. EIA [Online], *The Basics of Underground Natural Gas Storage*, released November 16, 2015, September 2016, www.eia.gov/naturalgas/storage/basics/.

[2]Niska Gas Storage [Online], 2010, *Gas Storage Industry Primer*, September 2016, www.niskapartners.com/wp-content/uploads/2010/04/GasStorageIndustryPrimer.pdf.

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What is SCADA?

7 minute read

SCADA Explained

Supervisory control and data acquisition (SCADA) is a system of software and hardware elements that allows industrial organizations to:

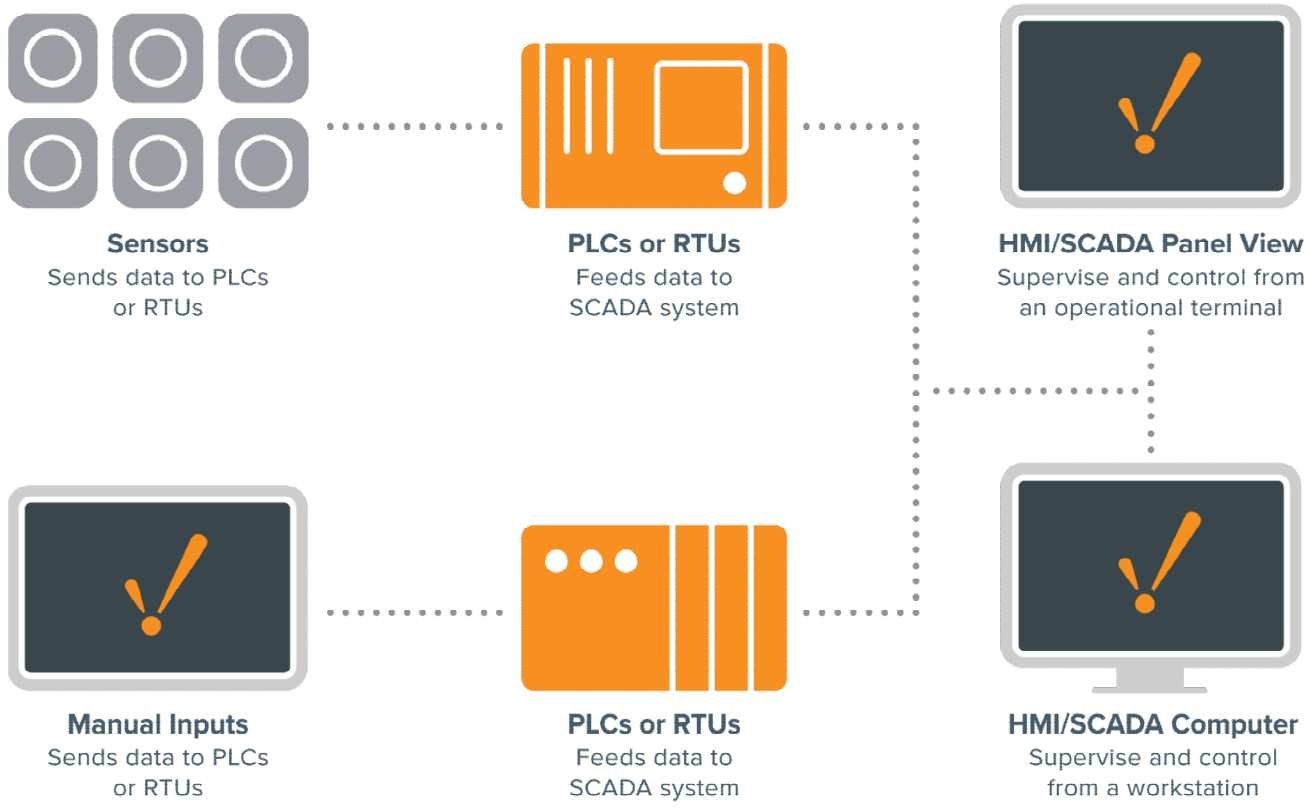
- Control industrial processes locally or at remote locations
- Monitor, gather, and process real-time data
- Directly interact with devices such as sensors, valves, pumps, motors, and more through human-machine interface (HMI) software
- Record events into a log file

SCADA systems are crucial for industrial organizations since they help to maintain efficiency, process data for smarter decisions, and communicate system issues to help mitigate downtime.

The basic SCADA architecture begins with programmable logic controllers (PLCs) or remote terminal units (RTUs). PLCs and RTUs are microcomputers that communicate with an array of objects such as factory machines, HMIs, sensors, and end devices, and then route the information from those objects to computers with SCADA software. The SCADA software processes, distributes, and displays the data, helping operators and other employees analyze the data and make important decisions.

For example, the SCADA system quickly notifies an operator that a batch of product is showing a high incidence of errors. The operator pauses the operation and views the SCADA system data via an HMI to determine the cause of the issue. The operator reviews the data and discovers that Machine 4 was malfunctioning. The SCADA system's ability to notify the operator of an issue helps him to resolve it and prevent further loss of product.

A Basic SCADA Diagram



Who Uses SCADA?

SCADA systems are used by industrial organizations and companies in the public and private sectors to control and maintain efficiency, distribute data for smarter decisions, and communicate system issues to help mitigate downtime. SCADA systems work well in many different types of enterprises because they can range from simple configurations to large, complex installations. SCADA systems are the backbone of many modern industries, including:

- Energy
- Food and beverage
- Manufacturing
- Oil and gas
- Power
- Recycling
- Transportation
- Water and waste water
- And many more

Virtually anywhere you look in today's world, there is some type of SCADA system running behind the scenes: maintaining the refrigeration systems at the local supermarket, ensuring production and safety at a refinery, achieving quality standards at a waste water treatment plant, or even tracking your energy use at home, to give a few examples.

Effective SCADA systems can result in significant savings of time and money. Numerous case studies have been published highlighting the benefits and savings of using a modern SCADA software solution such as Ignition.

The Birth of SCADA

DOE's Office of Scientific and Technical Information (OSTI), Office of Science [Public domain], via Wikimedia Commons

To understand the origins of SCADA, we must understand the problems industrial organizations are trying to solve. Before the concept of SCADA was introduced in the mid-20th century, many manufacturing floors, industrial plants, and remote sites relied on personnel to manually control and monitor equipment via push buttons and analog dials.

As industrial floors and remotes site began to scale out in size, solutions were needed to control equipment over long distances. Industrial organizations started to utilize relays and timers to provide some level of supervisory control without having to send people to remote locations to interact with each device.

While relays and timers solved many problems by providing limited automation functionality, more issues began to arise as organizations continued to scale out. Relays and timers were difficult to reconfigure, fault-find and the control panels took up racks upon racks of space. A more efficient and fully automated system of control and monitoring was needed.

In the early 1950s, computers were first developed and used for industrial control purposes. Supervisory control began to become popular among the major utilities, oil and gas pipelines, and other industrial markets at that time. In the 1960s, telemetry was established for monitoring, which allowed for automated communications to transmit measurements and other data from remotes sites to monitoring equipment. The term “SCADA” was coined in the early 1970s, and the rise of microprocessors and PLCs during that decade increased enterprises’ ability to monitor and control automated processes more than ever before.

The Evolution of SCADA

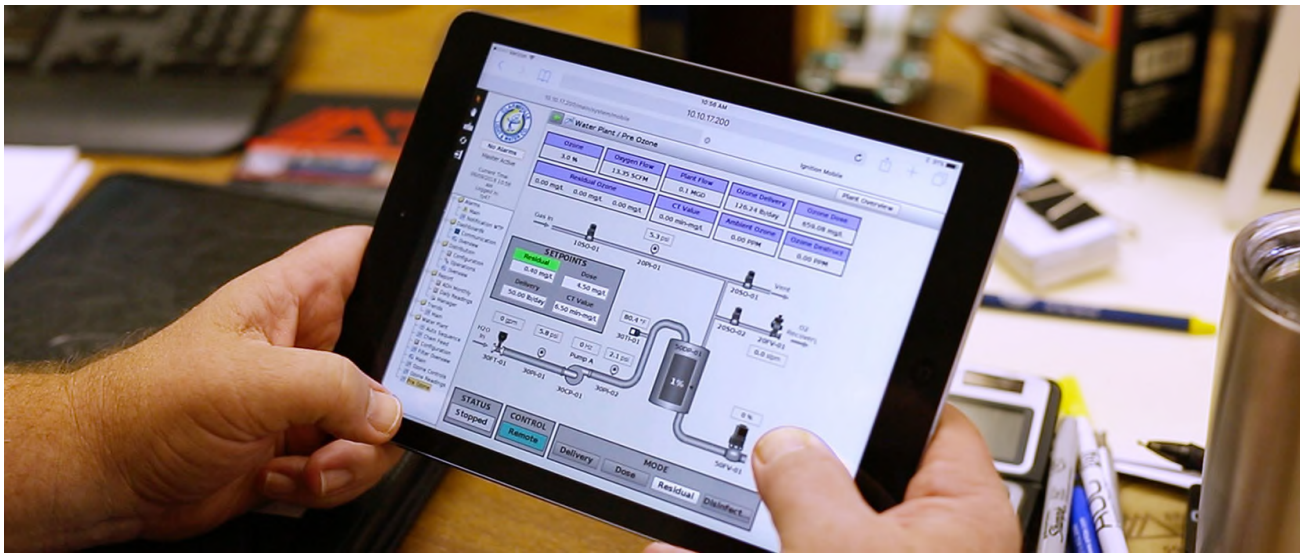
The first iteration of SCADA started off with mainframe computers. Networks as we know them today were not available and each SCADA system stood on its own. These systems were what would now be referred to as monolithic SCADA systems.

In the 80s and 90s, SCADA continued to evolve thanks to smaller computer systems, Local Area Networking (LAN) technology, and PC-based HMI software. SCADA systems soon were able to be connected to other similar systems. Many of the LAN protocols used in these systems were proprietary, which gave vendors control of how to optimize data transfer. Unfortunately, these systems were incapable of communicating with systems from other vendors. These systems were called distributed SCADA systems.

In the 1990s and early 2000s, building upon the distributed system model, SCADA adopted an incremental change by embracing an open system architecture and communications protocols that were not vendor-specific. This iteration of SCADA, called a networked SCADA system, took advantage of communications technologies such as Ethernet. Networked SCADA systems allowed systems from other vendors to communicate with each other, alleviating the limitations imposed by older SCADA systems, and allowed organizations to connect more devices to the network.

While SCADA systems have undergone substantial evolutionary changes, many industrial organizations continued to struggle with industrial data access from the enterprise level. By the late 1990s to the early 2000s, a technological boom occurred and personal computing and IT technologies accelerated in development. Structured query language (SQL) databases became the standard for IT databases but were not adopted by SCADA developers. This resulted in a rift between the fields of controls and IT, and SCADA technology became antiquated over time.

Traditional SCADA systems still use proprietary technology to handle data. Whether it is a data historian, a data connector, or other means of data transfer, the solution is messy and incredibly expensive. Modern SCADA systems aim to solve this problem by leveraging the best of controls and IT technology.



Modern SCADA Systems

Modern SCADA systems allow real-time data from the plant floor to be accessed from anywhere in the world. This access to real-time information allows governments, businesses, and individuals to make data-driven decisions about how to improve their processes. Without SCADA software, it would be extremely difficult if not impossible to gather sufficient data for consistently well-informed decisions.

Also, most modern SCADA designer applications have rapid application development (RAD) capabilities that allow users to design applications relatively easily, even if they don't have extensive knowledge of software development.

The introduction of modern IT standards and practices such as SQL and web-based applications into SCADA software has greatly improved the efficiency, security, productivity, and reliability of SCADA systems.

SCADA software that utilizes the power of SQL databases provides huge advantages over antiquated SCADA software. One big advantage of using SQL databases with a SCADA system is that it makes it easier to integrate into existing MES and ERP systems, allowing data to flow seamlessly through an entire organization.

Historical data from a SCADA system can also be logged in a SQL database, which allows for easier data analysis through data trending.

Learn About Ignition - The New SCADA

Ignition HMI/SCADA Software

Ignition by Inductive Automation® is an industrial automation software platform that many businesses and organizations have switched to for their HMI/SCADA needs.

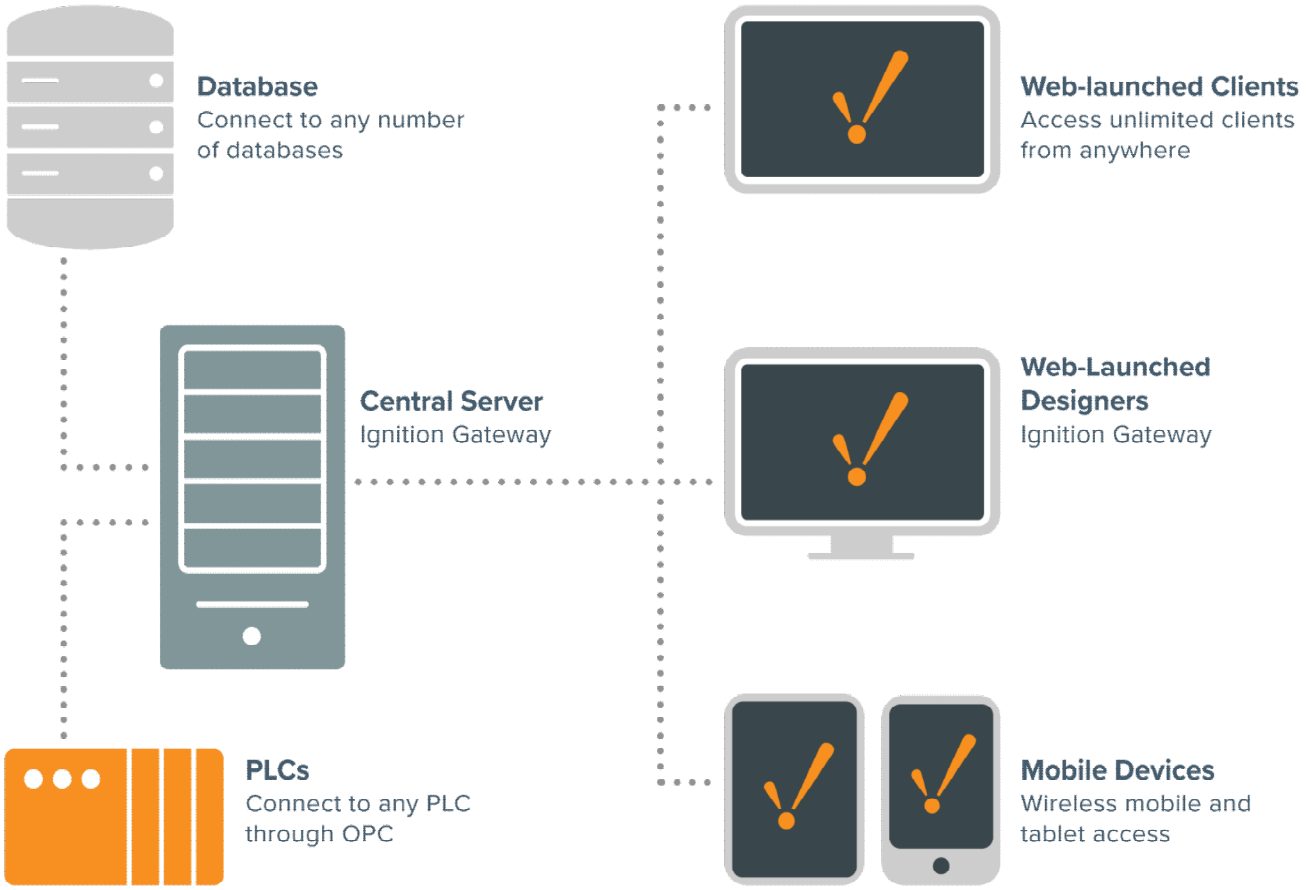
Ignition has been installed in thousands of locations in over 100 countries since 2010. Its powerful and robust nature allows SCADA system integrators to reach the demands of their customers while costing less than other SCADA software solutions.

Here are a few reasons why more enterprises are choosing Ignition:

- Ignition uses modern IT practices that make it compatible with current SCADA system components.
- Its unique licensing model lets users pay a flat fee based on the number of servers. Other SCADA vendors typically charge per client or per tag, but Ignition offers unlimited clients and tags.
- Ignition is web-deployable: it can be downloaded and installed in a few minutes, and clients can be launched or updated instantly.

Inductive Automation's motto of "Dream It, Do It" is a perfect embodiment of what Ignition can do. While its bold claims may sound too good to be true, one demonstration of the software proves how powerful it really is. Once you see what's possible, you'll begin to imagine how the software can fit your SCADA needs and open up new possibilities.

Ignition SCADA Architecture



Posted on September 12, 2018

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- Reporting (/solutions/reporting)
- Edge Computing (/ignition/edge)
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- Module Showcase (/moduleshowcase)

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Resources

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Partners

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- Integrator Program (/integrators)
- Distributor Program (/distributors)

STRATEGIC PARTNERS

- Cirrus Link Solutions (/ignition/modules#cirrus-link-solutions)
- Sepasoft (/ignition/modules#sepasoft)

IGNITION ONBOARD

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- Onboard Devices (/onboard)

Support

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- Knowledge Base (https://support.inductiveautomation.com/kb)
- Forum (https://forum.inductiveautomation.com/)
- Support Policy (https://support.inductiveautomation.com/?iaenhanc
- Website Help (/website-help)

TRAINING

- Inductive University (https://www.inductiveuniversity.com)
- Training Schedule (/training)
- Become Ignition Certified (/resources/training/certifications)
- Upload Test (/resources/upload)

About

COMPANY

- About Home (/about)
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- Founder's Message (/about/founders-message)
- Careers (/about/careers)

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Brand Resources (https://company-36882.frontify.com/d/PvUNchzTCkyj/inductive-automation-brand-guidelines)

Ex. I – 72

PACIFIC GAS & ELECTRIC COMPANY
GUIDE TO RECORD RETENTION

GAS SUPPLY

RECORD TITLE	FORM NUMBER	RETENTION JUSTIFICATION	RETENTION PERIOD
Analysis Gas Produced & Purchased		FERC 22I	Gas Production - 6 years (including btu & sulfur content)
As-Built Records Of Facilities		FERC 36A	Life of Facility
Chart - Gas Purchase		GSIP 457-1	4 years
Contracts			See Accounting & Corporate Records
Correspondence - All Types		FERC 63A	Retain for the period prescribed for the item to which it relates where necessary to a proper explanation of same.
Emergency Curtailment Procedures		FERC 29B	Destroy at option after expiration or supersession
Emergency Shutdown Procedures		FERC 29B	Destroy at option after expiration or supersession
Engineering Records Drawings & Support Data		FERC 36A	Records pertinent to the constructed facility retain until superseded or 6 years after the facility is retired. If construction of facility does not result, destroy at option after a complete accounting of expenses incurred.
Gas Measuring Records		FERC 22N	Gas Production - retain 1 year, except where basic chart information is transferred to another record, the charts need only be retained 6 months provided the record containing the basic date is retained one year.
Gas Produced & Purchased Records		FERC 22H	Gas Production - 6 years
Gas Sent Out And Holder Stock Records		FERC 22H	Gas Production - 6 years
Gas Well Test Report	61-6084	GSIP 459-1	3 years after the gas well is abandoned
Logs – Boiler		FERC 22A	Gas Production - 3 years Retention included related documents
Logs - Gas Generation & Output		FERC 22B	Gas Production - 6 years Retention includes related documents.
Logs - Gas Machine		FERC 22A	Gas Production - 3 years Retention includes related documents
Logs - Temperature & Atmospheric Pressure		FERC 22C	Gas Production - 3 years
Maps - Underground Storage Of Natural Gas		FERC 23.1C	1 year after reservoir, field, or relevant storage area is abandoned.
Meter Test Records		FERC 23M	Gas Production - 1 year after meter is retired

Note: Retention periods shown are only valid as of the date of this report and may not reflect lawful requirements or regulatory changes placed into effect since the report was printed.

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PACIFIC GAS & ELECTRIC COMPANY
GUIDE TO RECORD RETENTION

GAS SUPPLY

RECORD TITLE	FORM NUMBER	RETENTION JUSTIFICATION	RETENTION PERIOD
Record Of General Inspection & Operating Tests		FERC 22J	Gas Production - 3 years
Report Of Coal/Coke/Oil		FERC 22D	Gas Production - 3 years
Residual Report		FERC 22E	Gas Production - 3 years
Routine Maintenance Completion Report	62-3423	Gas Supply	6 years
Test Of Heating Value At Stations & Outlying Points		FERC 22G	Gas Production - 6 years
Weekly Report Heating Value & Specific Gravity	62-3903	FERC 22J	3 years
Well Records - Gas Production		FERC 22K	Retain one year after field or relevant production area is abandoned. (including clearing, bailing, shooting, etc., records; rock pressure; open flow; production; gas analysis reports, etc.)
Well Records - Underground Storage Of Natural Gas		FERC 23.1A	Well records, reports and logs which includes data relating to pressures, injected volumes, withdrawn volumes, core analysis, daily volumes of gas injected into and withdrawn from reservoir, and cushion and working gas volumes for each reservoir. Retain 1 year after reservoir, field, or relevant storage area is abandoned.

Note: Retention periods shown are only valid as of the date of this report and may not reflect lawful requirements or regulatory changes placed into effect since the report was printed.

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Ex. I – 73

TIMOTHY L. HOWER, P. E.
Senior Technical Advisor

MHA Petroleum Consultants
730 17th Street, Suite 410
Denver, Colorado 80202 USA
Phone: +1 303 277 0270
Mobile: +1 303 204 0220
e-mail: thower@mhausa.com

EDUCATION

- B. S., Petroleum Engineering, Penn State University, 1981
- M. S., Petroleum Engineering, Penn State University, 1983

PROFESSIONAL PROFILE

In excess of thirty-six years of petroleum engineering evaluation experience including:

- Supervision/Project Management of technical studies including
  - Independent Expert on major international unitization and equity redetermination projects, mergers and acquisitions, arbitrations, and joint venture field development programs.
  - Integrated geological modeling, reservoir characterization and numerical simulation studies conducted worldwide.
  - Evaluation, assessment and field development planning for shale gas and shale oil reservoirs in the US, Europe, China, South Africa and Australia.
  - Reserve valuations, equity studies and acquisition due diligence of major oil and gas assets located in the domestic US and worldwide.
  - Assessment and evaluation of enhanced oil recovery (EOR) projects, including waterflooding, CO_2 injection, miscible and immiscible natural gas injection.
- Evaluation and optimization of underground gas storage projects, including Compressed Air Energy Storage (CAES) projects located in the U.S., Europe and Australia. Conducted industry training courses on reservoir engineering of underground gas storage reservoirs, and co-authored an industry textbook on gas storage reservoir management.
- Unconventional gas reservoir development (coalbed methane, shales, tight gas). Authored and presented industry training courses on coalbed methane and tight gas reservoirs.
- Black oil, compositional, and unconventional reservoir simulation studies (North/South America, Europe, Africa, Australia, New Zealand and China).
- Design and implementation of pressure transient testing programs for reservoir characterization and evaluation.

- Development and instruction of reservoir engineering, enhanced oil recovery (EOR), production optimization and reservoir simulation industry training courses offered through OGCI-Petroskills.
- Manager of software client support and instruction of training courses for the ECLIPSE suite of reservoir simulation software products.
- Expert witness testimony and testimony before various regulatory commissions, the London High Courts, the London Court of International Aribtration, the High Court of New Zealand, and the Supreme Court of South Australia.

Registered Professional Engineer: Colorado, Wyoming U.S.A.

WORK EXPERIENCE

MHA PETROLEUM CONSULTANTS, a Sproule Company, Denver, Colorado:
(July, 1997 – July 2019) **President and CEO**
(July 2019 – Present) **Senior Technical Advisor**
Responsible for the day to day operations of an organization of approximately 25 people with active engineering projects throughout the world. In charge of staff development, staff recruitment, development of new business and new business contacts, as well as maintaining relationships with the company's existing client base. Project Manager of numerous engineering consulting projects worldwide. Instruction and development of industry training courses.

ENRON OIL & GAS COMPANY, Denver, Colorado and Houston, Texas:
(October, 1995 to June, 1997) **Engineering Manager**
In charge of a staff of reservoir, production engineers, and support personnel. Responsible for property evaluations, exploration and exploitation drilling programs, secondary recovery design and implementation, reservoir simulation studies, reserve and acquisition evaluations, and annual budgeting and forecasting for EOG's largest division.

INTERA Petroleum Division, Denver, Colorado:
(October, 1990 to September, 1995) **Sr. Manager, E&P Studies; Consulting Engineer**
Manager of the North American consulting group which included a staff of more than 30 geologists, geophysicists, petrophysicists and engineers. Responsible for staff development, staff recruitment, and profit/loss for Intera's largest global consulting group. Provided engineering, simulation and software support services for clients in North and South America, Europe, Africa, Australia and China.

CNG Development Company, Pittsburgh, Pennsylvania:
(October, 1988 to September, 1990) **Staff Engineer**
Management of oil and gas properties in conventional and unconventional (tight sands, shales, and coalbed) reservoirs. Production forecasting, field optimization, reserve estimates, formation evaluation, and depletion and drainage studies.

TENNECO OIL Exploration and Production, Denver, Colorado:
(June, 1983 to September, 1988) **Senior Reservoir Engineer**
Responsible for management of oil and gas properties in the Rocky Mountain Region. Unitization studies for several enhanced recovery projects in North Dakota. Lead engineer for Tenneco's significant interests in the San Juan Basin of New Mexico.

PROFESSIONAL MEMBERSHIPS

- Elected in 2015 as a Society of Petroleum Engineers (SPE) Distinguished Member.
- C. Drew Stahl Distinguished Alumni Achievement Award presented by the Pennsylvania State University, April 2011.
- Chairman – Denver Section of the SPE; 2001/2002.
- SPE *Henry Matson Technical Service Award,* May 2000, for innovative contributions in the field of engineering in gas reservoirs.
- Chairman; SPE Reprint Series on Layered Reservoirs
- Editor; SPE Reprint Series on Reservoir Management
- Professional Engineering Registration Committee
- General Chairman, 1993 SPE Low Permeability Reservoirs Symposium
- Program Chairman, SPE Low Permeability Reservoirs Symposium (1995, 1998, 2000)
- SPE Gas Technology Committee; SPE Reprint Series Committee
- SPE Distinguished Lecturer Selection Committee
- General Chairman; 2005 SPE Rocky Mountain Technical Conference

PUBLICATIONS

1. Sipeki, J. and Hower, T.L., "Impact of Operator's Best Practices, Completion Design and Well Density on Projected Ultimate Recoveries of Horizontal Bakken Wells in Williams County, North Dakota", to be presented at the 2013 Unconventional Resources Technology Conference (URTeC), Denver, Colorado, 12-14 August.

2. Aldrich, J., Hower T.L., and Sipeki, J., "Assessing and Advancing a CBM Resource Play Towards Commerciality – A Case Study From the UK; PEDL 159 Solway Basin", presented at the AAPG 2012 International Convention, Singapore, September 2012.

3. "Certification of Reserves and Resources for CSG Assets", workshop presented at the Asia Pacific CBM Forum, 8 May 2011, Brisbane.

4. "Modeling Unconventional Gas Reservoirs", workshop presented 20-21 February 2010, Adelaide, Australia.

5. "Performance Evaluation of CSG Reservoirs", workshop presented 17-19 February 2010, Brisbane, Australia.

6. "Reservoir Aspects of Unconventional Gas Resources: Coalbed Methane, Shales and Tight Gas", workshop presented at the SMi Unconventional Gas Conference, London, April, 2009

7. "Coalbed Methane Geology, Engineering and Reserves", workshop presented January, 2009, Kuala Lumpur, Malaysia.

8. "Coalbed Methane – Progressing from Resource to Reserves", workshop presented at the SMi Unconventional Gas Conference, London, March, 2008

9. "Coalbed Methane Reserves Workshop", Brisbane, Australia, 2008

10. “Recent Developments in Forecasting Coal Seam Methane Production”, presentation for the Brisbane, Australia SPE Section, 15 February 2005.

11. “A U.S. Perspective. Forecast for the Future – Reliability of Supply and Deliverability of Coal Seam Methane Resources”, presentation at the December 2003 Australian CBM Conference in Brisbane.

12. Hower, T.L., “Coalbed Methane Reservoir Simulation: An Evolving Science,” paper SPE 84424 presented at the 2003 SPE Annual Technical Conference and Exhibition, Denver, Colorado, 5-8 October.

13. Hower, T.L., Jones, J.E., Goldstein, D., Harbridge, W.: “Development of the Wyodak Coalbed Methane Resource in the Powder River Basin,” paper 84428 presented at the 2003 SPE Annual Technical Conference and Exhibition, Denver, Colorado, 5-8.

14. Gas Reservoir Management, Applied Reservoir Engineering, Reservoir Engineering for Others; technical training manuals for OGCI/Petroskills industry training courses; 2001/2002.

15. *Principles of Reservoir Engineering* and *Reservoir Engineering Mechanisms,* technical training manuals for British Petroleum Corp., Sunbury, UK; 1999.

16. *Managing Water-Drive Gas Reservoirs,* co-author of the textbook published by the Gas Research Institute, Chicago, Ill, 1993.

17. *Gas Reservoir Management* and *Gas Reservoir Modeling,* technical training manuals for Amoco Production Company, Houston, Texas, 1993.

18. Hower, T.L., Fugate, M.W., and Owens, R.W.: “Improved Performance in Aquifer Gas Storage Fields Through Reservoir Management”, paper SPE 26172 presented at the 1993 Gas Technology Symposium, 28-30 June, 1993, Calgary, Alberta.

19. Hower, T.L., and Owens, R.W.: “Reservoir Management of a Gulf Coast Water-Drive Gas Field”, presented at the 1992 International Gas Research Conference, 16-19 November, Orlando, Florida.

20. Hower, T.L., Lewis, D.R., and Owens, R.W.: “Recovery Optimization in a Multi-reservoir Offshore Gas Field with Water Influx”, paper SPE 24865 presented at the 1992 SPE Annual Technical Conference and Exhibition, 4-7 October, Washington, D.C.

21. Hower, T.L., and Decker, M.K.: “Identifying Recompletion Candidates in Stratified Gas Reservoirs”, presented at the 1992 Mid-Continent Gas Symposium, 13-14 April, Amarillo, Texas.

22. Hower, T.L. and Jones, R.E.: “Predicting Recovery of Gas Reservoirs Under Water-Drive Conditions”, paper SPE 22937 presented at the 1991 SPE Annual Technical Conference and Exhibition, 6-9 October, Dallas.

23. Hower, T.L.: “Using Depletion Ratios to Select and Evaluate Drilling Locations in Naturally Fractured Gas Reservoirs”, paper SPE 20758 presented at the 1990 SPE Annual Technical Conference and Exhibition, 23-26 September, New Orleans.

Ex. I – 74

Charles E. Stinson, PE

Petroleum Engineering and Project Development

Underground Gas Storage - Pipelines & Facilities - Gas Production

Petroleum Engineer with over 40 years of broad experience in the natural gas industry, upstream and downstream, involving ventures both regulated and non-regulated, domestic and Canadian. This includes extensive experience in the permitting, development and operations of underground storage facilities in Oregon and California, both as an employee of the operating companies (1978 to 2011) as well as a professional engineering consultant (2011 to present).

Areas of Expertise

Twenty-five years in management and executive roles with operational and fiscal responsibility for activities including:

- Underground Storage Development & Ops
- Natural Gas Gathering & Processing
- Distribution Facilities Design
- Gas & Oil Exploration & Production
- Transmission Pipeline Construction
- Natural Gas Marketing
- Producing Property Acquisitions
- Supply Resource Management
- Gas Facility Operations & Maint.
- Regulatory Compliance

Positions Held

Beginning his professional career as a field petroleum engineer, Mr. Stinson's experience allowed him to advance to positions in senior management with multiple technical staff working under his direction. Following are the senior management positions achieved during his corporate career:

- Vice President, Engineering & Operations – NW Natural Gas Storage LLC
- Vice President, Engineering & Operations – Gill Ranch Storage LLC
- Managing Director & Chief Engineer – NW Natural, a local gas distribution co. in Oregon
- President – Canor Energy Ltd, Canadian oil & gas exploration company
- Vice President & General Manager – Oregon Natural Gas Development Co.
- President – Westar Marketing Company, gas marketing subsidiary of NW Natural

Professional Registration

Registered Petroleum Engineer in the State of Oregon, #11,498, February 1982

Professional Affiliations

Society of Petroleum Engineers
Northwest Energy Association (past chairman and director)
American Gas Association Underground Storage Committee (past chairman)
Western Energy Institute (past chairman of Operating Section)

Education

B. S. Applied Mathematics, University of Colorado

CS Energy Ventures
cstinson@csenergyventures.com

Noteworthy Accomplishments in Gas Storage

American Gas Association Underground Storage Committee – Mr. Stinson served on the AGA UGS committee for over 20 years, including one year as its chairman. This committee included operators of the majority of gas storage fields in the U.S. and served as a platform for them to share emerging technologies, current best practices, development and operating challenges, regulatory changes, and a host of other issues facing their companies. As a result of committee meetings held at various operating company sites, Mr. Stinson has toured over 30 gas storage fields in 13 states.

Gill Ranch Storage Project – A 20 Bcf underground gas storage project located in Central California, jointly owned by Gill Ranch Storage LLC and PG&E. Mr. Stinson had overall accountability for the project development, including all aspects of the project screening & selection, design, permitting, and construction. The project sought and received a mitigated negative environmental declaration from the California Public Utility Commission and completed the certificate of convenience and necessity in a period of 16 months allowing the construction to proceed and achieve the target startup date in October 2010.

Mist Gas Storage Field – Mr. Stinson has been instrumental in the development of the Mist Gas Storage Field over the past 35 years. Development initially kicked off in 1985, and its first underground gas storage operation commenced in 1989. Since that time, it has undergone multiple expansions and currently has 8 reservoirs accounting for over 20 Bcf of working gas capacity. All phases of this development were completed under Mr. Stinson's management and direction.

South Mist Feeder Loop & Pipeline Extension – These two projects comprised 97 miles of 24" gas transmission pipeline, built to expand the takeaway capacity of the Mist Gas Storage Field described above. As Director of Project Development, Mr. Stinson had overall management responsibility for the design, permitting and construction of these projects. The permitting was very contentious, and ultimately the approved permit was challenged to the Oregon Supreme Court. It was upheld by virtue of the project team's diligence and strict compliance with the intent of the law. The last phase of these projects went operational in 2004. Together they have operated continuously without issue.

Private Property Storage Evaluation – Mr. Stinson performed an assessment of the underground storage potential of a nearly depleted natural gas reservoir. The property owner commissioned this study of a gas field located wholly on their property in Northern California. This study included not only an analysis of the physical attributes of the gas reservoir, but also the current market conditions for storage development and the need for additional storage capacity in California.

Pacific Gas & Electric CAES Project – As a member of the Compressed Air Energy Storage (CAES) project team, Mr. Stinson headed up the subsurface team in providing expertise and guidance in the selection of suitable reservoirs for testing and potential development. Mr. Stinson was designated as the Compression Test Manager for the reservoir testing program performed in early 2015. The CAES project was designed to test the feasibility of storing sufficient volumes of air in an underground depleted natural gas reservoir to provide 300 MW of electric power during periods of peak demand. The project is available for commercial development.

Gas Storage Facility Risk Assessments– Mr. Stinson headed up teams of gas storage professionals to perform risk assessments for two gas storage facilities in the western U.S. in compliance with new regulations for underground gas storage.

Litigation Support - Mr. Stinson has provided expert witness services in two litigations involving underground gas storage facilities, one in California and the other in the Midwest.