SoCalGas-4-2

Prepared Reply Testimony of Tim Hower and Charlie Stinson of MHA Petroleum Consultants (March 20, 2020)

I.19-06-016

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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 June 27, 2019)

CHAPTER I

PREPARED EXPERT TESTIMONY OF TIM HOWER AND CHARLIE STINSON OF MHA PETROLEUM CONSULTANTS ON BEHALF OF SOUTHERN CALIFORNIA GAS COMPANY (U 904 G)

March 20, 2020

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CHAPTER I

I. INTRODUCTION.

The purpose of the following prepared reply testimony, submitted on behalf of the Southern California Gas Company ("SoCalGas"), is to address the testimonies of Margaret Felts on behalf of the California Public Utilities Commission's ("Commission") Safety Enforcement Division ("SED")[1] and Mina Botros, Alan Bach, Matthew Taul, Pui-Wa Li, and Tyler Holzschuh on behalf of the Public Advocates Offices ("Cal Advocates"). SED alleges SoCalGas violated California Public Utilities Code Section 451 (Section 451) because it did not conduct failure analyses at Aliso Canyon (Violations 1-60),[2] failed to follow its plan to check the casing of 13 wells for metal loss (Violations 61-73),[3] operated SS-25 without a backup mechanical barrier to the production casing (Violation 77),[4] did not have a policy that required well casing wall thickness inspection and measurement (Violation 78),[5] did not appropriately understand and address groundwater (Violations 84-85),[6] did not fully cement or cathodically protect the casing against corrosion (Violation 86),[7] failed to have a continuous pressure monitoring system and thereby prevented immediate identification of the leak (Violation 87),[8] and had imprudent and unreasonable recordkeeping practices (Violations 327-329).[9] Cal Advocates alleges further that

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[1] SED's Opening Testimony was served on parties to I.19-06-016 on November 22, 2019 without an identified witness, and remains so. Pursuant to SoCalGas Data Request 2 to SED, SED identified Margaret Felts as the sponsoring witness for the entirety of SED's Opening Testimony. *See* Ex. I-1 (SED Response to SoCalGas Data Request 2).
[2] SED Opening Testimony at 7.
[3] *Id.* at 10.
[4] *Id.* at 18.
[5] *Id.* at 25.
[6] *Id.* at 39.
[7] *Id.* at 45.
[8] *Id.* at 47.
[9] *Id.* at 67.

SoCalGas did not identify and resolve well integrity issues,[10] did not conduct failure analyses,[11] did not take prudent action on the circa 1988 Vertilog results,[12] and generally failed to take a proactive approach to maintaining the Aliso Canyon facility.[13] However, these allegations are incorrect and/or misguided, as explained in detail below. SoCalGas did conduct appropriate failure analyses, had well monitoring programs that became more proactive as technological advancements in tools allowed, and had an understanding of groundwater levels consistent with what was necessary. Moreover, SoCalGas' practices were consistent with or exceeded what we have observed in the industry. Even today, dual barrier designs are not industry standard, nor is cathodic protection. And, real-time pressure monitoring would not have informed how the SS-25 leak was addressed. Finally, compared to what we have seen at other operators in the industry, SoCalGas' records are well organized and contain the appropriate and necessary information.

Our expertise is based on significant experience in the gas storage industry. We, Tim Hower and Charlie Stinson, have over 75 years of collective experience in the natural gas and natural gas storage industries. Mr. Hower's experience includes the evaluation and optimization of underground gas storage projects located in the U.S., Europe and Australia. He has conducted industry training courses on the engineering of gas storage reservoirs, and he has co-authored an industry textbook on gas storage reservoir management.[14] Much of Mr. Hower's experience has involved working directly with the operation engineers and staff at the natural gas storage facilities ensuring that their field management techniques conform to industry standard practices.

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[10] Public Advocates Office Opening Testimony at 3.
[11] *Id*. at 13.
[12] *Id*. at 3.
[13] *Id*. at 13.
[14] Paul S. Schafer, Tim Hower & Raymond W. Owens, Managing Water-Drive Gas Reservoirs (Gas Research Institute 1993).

Mr. Hower has previously testified as an Expert on gas storage industry standard practices before numerous jurisdictions and regulatory bodies. Mr. Hower has toured 27 gas storage fields in 8 states.

Mr. Stinson's experience includes the permitting, development and operations of underground storage facilities in Oregon and California, both as an employee of operating companies (1978 to 2011) as well as a professional engineering consultant (2011 to present). In addition, Mr. Stinson served on the American Gas Association Underground Gas Storage committee for over 20 years, including one year as its chairman. This committee served as a platform for gas storage operators to share emerging technologies, current industry standard 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 33 gas storage fields in 13 states.

II. GENERAL DISCUSSION REGARDING INDUSTRY STANDARDS AND SOCALGAS' OPERATIONS.

In considering whether SoCalGas acted reasonably with respect to operation and maintenance of the Aliso Canyon gas storage field prior to the 2015 Aliso Canyon incident it is necessary to assess the relevant industry standards that applied at the time. Based on our knowledge and experience from working onsite at 60 U.S. gas storage fields, and working with engineers and field data on approximately 135 gas storage fields over the past 40 years, we have first-hand knowledge gas storage operations and standard practices.

Prior to September 2015 and the publication of API Recommended Practice ("RP") 1171 ("API RP 1171"), "Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs," there were no documented gas storage industry-wide procedures that would have been considered industry standard practice.[15] Even now, API RP 1171 remains a "Recommended Practice,"[16] which is in the process of implementation and does not qualify as an industry standard.

Of course, even absent formal documented standards, there were industry standard practices even if they were not recorded or documented. The following is a summary table comparing applicable Division of Oil, Gas and Geothermal Resources ("DOGGR"), now renamed The Geologic Energy Management Division ("CalGEM"), regulations in effect at the time of the SS-25 release, the API RP 1171 recommendations, standard industry practices we observed, and those utilized at Aliso Canyon as of October 23, 2015:

STORAGE ATTRIBUTE	**DOGGR REGULATIONS AS OF 10/23/2015**[17]	**API RP 1171 RECOMMENDED PRACTICES**[18]	**INDUSTRY STANDARD PRACTICE AS OF 10/23/2015**[19]	**PRACTICE AT ALISO CANYON AS OF 10/23/2015**
Maximum Operating Reservoir Pressure	Defined by permit (3,600 psi for Aliso)[20]	Not specified	36% of storage reservoirs operate higher than original discovery (delta pressure)[21]	Original discovery only. Delta pressure approved by DOGGR but never implemented

[15] For purposes of this testimony "industry standard practice" means prevailing practice within the industry.
[16] *See* Ex. I-2 (Pipeline and Hazardous Materials Storage Administration, Underground Natural Gas Storage (2020), https://www.phmsa.dot.gov/pipeline/underground-natural-gas-storage/underground-natural-gas-storage) (referring to API RP 1170 and 1171 as a "recommended practices").In the final rule, PHMSA adopted most of the recommendations in 1171 with some changes, mostly related to compliance deadlines. *See* Ex. I-3 (Pipeline Safety: Safety of Underground Natural Gas Storage Facilities, 85 Fed. Reg. 8104) (Feb. 12, 2020) (adopting the recommended practices of API RP 1171 with changes based on comments on the interim final rule).
[17] *See* Cal. Code Reg. § 1724 - §1724.10, et seq.
[18] *See* Ex. I-4 (API 1171).
[19] Based on personal knowledge and experience of Tim Hower and Charlie Stinson.
[20] Ex. I-5 (DOGGR Project Approval Letter, April 18, 1989; revised July 26, 1989).
[21] Based on the personal knowledge and experience of Charlie Stinson.

Mechanical Integrity Test - Original	Within 3 months of initial operations	Well mechanical integrity tests required	Tested during well completion operations	Tests completed during well conversion - completion
Mechanical Integrity Test - Operations	Annual temperature surveys	Wells monitored for unexpected conditions	Annual temperature surveys	Wells visited daily. Temp logs ran annually.
Well Casing Design	Dual barrier not required	Dual barrier not required	87% of all gas storage wells are single barrier[22]	Packer installed. Single barrier operation.
Cement Bond Log	Required	Required	Typically completed	Completed on all wells
Max Age of Storage Wells	None specified	None specified	Median age of repurposed wells is 74 years[23]	SS-25 was 61 years old at the time of failure
Well Integrity Monitoring	Not required	Monitor for annular pressure	No programmatic application	Integrity logs run during well reworks
Wellsite Inspections	Not specified	Annual inspections	Highly variable	Daily visits. Monthly inspections.
Pressure Monitoring	Surface pressures weekly	Not required	Highly variable	Recorded weekly
Reservoir Integrity Monitoring	Not required	Material balance required periodically	Completed periodically	Inventory verification completed periodically
Production Casing Cement-to-Surface for Existing Wells	Not required	Not required	Highly variable	Completed in new wells post 1990

[22] Ex. I-6 (Underground Natural Gas Storage Operators "Tubing and Packers in Underground Natural Gas Storage: Safety and Reliability Considerations", AGA/API/INGAA Underground Natural Gas Storage Joint Industry Task Force, September 16, 2016).
[23] Ex. I-7 at 1 (Drew R. Michanowicz, et al., 2017 Env. Res. Lett. 12, 1 (2017)).

Emergency Shutdown Valves	Not required[24]	Not required. Operator to evaluate need based on criteria.	Only 11% surface ESDs installed. Only 4% have SSSv[25]	All IW wells with surface ESDs. SSSVs attempted but proved to be unreliable
Emergency Shutdown Valve Testing	Not required	At least annually	Highly variable	Semi-annually
Emergency Response Plan	Not required	Required	Typically completed	Completed
Well Flow Testing	Not required	Not specified	Highly variable	Periodic well flow tests for erosion control
Operation & Maintenance Procedures - Wells	Not required	Required	Typically completed	Completed
Risk Management Plan	Not required	Required	Typically informal only with little or no documentation	Informal pre-2007, Inspect and Replace, SIMP in early implementation as of 10/23/2015
Well Kill System	Not required	Not required	Not installed	Installed on all injection/withdrawal wells

[24] DOGGR regulations require emergency shutdown valves for critical wells only. Cal. Code Reg. § 1724.3. DOGGR defines a "critical well" as a well within 300 feet of "any building intended for human occupancy that is not necessary to the operation of the well; or any airport runway" or within 100 of "[a]ny dedicated public street, highway, or nearest rail of an operating railway that is in general use; [a]ny navigable body of water or watercourse perennially covered by water; [a]ny public recreational facility such as a golf course, amusement park, picnic ground, campground, or any other area of periodic high-density population; or [a]ny officially recognized wildlife preserve." Cal. Code Reg. § 1720. Regardless, Aliso Canyon does not have any critical wells.

[25] Ex. I-8 at 53-54 (Underground Natural Gas Storage Integrity & Safe Operations (July 6, 2016), available at https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/underground-natural-gas-storage/59336/aga-white-paper-ungs-integrity-and-safe-ops-20160706.pdf at 53-54)

In addition to API RP 1171, and subsequent to its publication, various members of gas industry associations developed a joint industry task force ("JITF") paper, "Underground Natural Gas Storage – Integrity & Safe Operations" published in July 2016.[26] The JITF observed that "[o]perators have projected full conformance with API 1171 following a final rulemaking could take 7-10 years. . .."[27] While the industry recognizes API RP 1171 as a common industry recommended practice, most operators' field facilities and operations will not be compliant for several years.[28]

SED's testimony fails to identify any violation of industry standards by SoCalGas. In addition, SED has generally demonstrated a lack of knowledge and of gas industry standard practice. In response to SoCalGas discovery requests, SED has produced numerous documents that it alleges are indicative of "industry standards."[29] Many of these are industry association technical research reports and case study papers. Notably, the research and case study papers provided by SED are not indicative of industry standard practice because they are not

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[26] Ex. I-8 (Underground Natural Gas Storage Integrity & Safe Operations (July 6, 2016), available at https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/underground-natural-gas-storage/59336/aga-white-paper-ungs-integrity-and-safe-ops-20160706.pdf).
[27] *Id.* at 4.
[28] *Id. See also* Ex. I-3 (Pipeline Safety: Safety of Underground Natural Gas Storage Facilities, 85 Fed. Reg. 8104) (Feb. 12, 2020) (noting the changes in compliance deadlines under the final rule (adopting, in part, RP 1171). Specifically, while written programs need to be in place for an integrity management framework within a year after the effective date, PHMSA does not expect parties to begin risk assessments until much later – providing four years from the effective date to do initial assessments of 40% of wellbores, wellheads and associated components. Moreover, PHMSA adopted these regulations in response to the Aliso Canyon incident). Additionally, DOGGR's regulations put in place post-incident contain long lead times to allow operators to prepare for compliance. *See, e.g.,* Cal. Code Reg. § 1726.3(d)(1) (allowing seven years after effectiveness of the regulations for initial compliance).
[29] *See, e.g.*, Ex. I-9 (SED Supplemental Data Response to SoCalGas Data Request 3 (as supplemented Jan. 23, 2020)), SED responses to questions 7(b) (naming 2007.0101.NACE-SP0186-NN as an alleged industry standard), 9(a) (citing scholarly articles and various other papers), 9(b) (same), 10(c) (same). Based on the dearth of formal industry standards, we use the term "industry standards" throughout this testimony to refer to the consistent practices we have observed first-hand through our work experiences.

representative of gas storage operators' prevailing practices. Further, SED objected to SoCalGas' questions about what SED contends SoCalGas should have done with respect to various operations and maintenance practices. SED responded simply that it was not SED's job to know how to operate a gas storage field.[30] Finally, we note that while we are responding to individual allegations made by SED and Cal Advocates, many of the violations and allegations overlap and are asserted based on the same underlying concepts and issues. Therefore, this testimony should be taken *as a whole* – the responses to individual allegations should be taken to respond to the specific allegations identified in each section as well as any other allegations related to the same underlying factual issue.

III. SOCALGAS ACTED REASONABLY IN INVESTIGATING PRIOR "LEAKS" AT THE FACILITY.

As discussed below, SoCalGas met or exceeded gas storage industry and industry standard practices regarding well failures and subsequent investigation into their causes. Moreover, SED and Blade mischaracterize the 60 or 63 well casing issues of varying cause and degree as "leaks."[31] Indeed, the number of actual casing leaks is less than half that number, and only two of those (FF-34A and Frew 3) were of the scale where gas migrated some distance in

[30] *See, e.g., Id.*, SED responses to questions 1(a), 2(a), 3(a), 4(a), 5(a), 7(a), 8(a), 9(a), 10(a), and 11(d). While objecting, SED noted that it is "SoCalGas' (not SED's) mandated responsibility, pursuant to California Public Utilities Code Section 451" [to determine what adequate (reasonable) measures might be in a specific scenario]. *See also* Ex. I-10 at 215:22-216:1 (Margaret Felts Depo. Tr., 215:22 – 216:1) (Counsel for SED representing Ms. Felt's at the deposition objecting and stating that "[i]t 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."). Later, the same counsel, in a separate objection, noted that it was "beyond the scope of SED's purview" to recommend how to investigate. *Id.* at 252:10-14.

[31] Note that SED's summary of violations lists 60 violations for "leaks," while the Blade Report lists 63 "casing leaks." SED Testimony at 2; Blade Report at 2. Even more unclear, SED states that there were "*over* 60 casing leaks at Aliso Canyon before the SS-25 incident." SED Testimony at 7. However, "[t]o avoid double counting violations that the 60 leaks identified before the Aliso Canyon included the six blowouts and parted casings identified above." *Id.* at 9; *see* section III-B for further discussion of the number of "leaks."

the subsurface away from the wellbore.[32]

A. <u>SoCalGas Detected, Investigated, and Remediated Well Casing Issues Consistent with Industry Standards.</u>

In its summary of violations, SED alleges 60 violations related to SoCalGas' alleged failure to adequately investigate casing "leaks."[33] SED alleges that "SoCalGas did not investigate or analyze its past casing leaks of other wells at Aliso Canyon. Moreover, in its recommendations for fixes to SoCalGas's system, SED states that "SoCalGas should be required to do an API Recommended Practice 585 level 1 analysis of all failures."[34] Importantly, however, aside from citing to API 585, SED fails to identify any particular deficiency or describe what precisely SED believes SoCalGas should have done. In response to questions from SoCalGas on this issue, SED objected that "[i]t 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."[35] Later, in a separate objection, SED noted that it was "beyond the scope of SED's purview" to recommend how to investigate.[36]

As of the date of the incident there was no documented industry standard related to investigation of casing failures in gas storage operations. In April 2014, API published Recommended Practice 585, "Pressure Equipment Integrity Incident Investigation" ("API RP 585").[37] It is important to note that this Recommended Practice does not apply to gas storage operations; it documents and details procedures for conducting incident investigations for other

[32] *See* Vol. 4, Blade Report at 51 ("Frew 3 and FF-34A had casing leaks and underground flow and were killed by pumping down the tubing.").
[33] SED Opening Testimony at 2.
[34] SED Opening Testimony at 79.
[35] Ex. I-10 at 215:22-216:1 (Felts Depo. Tr., 215:22 – 216:1).
[36] *Id.* at 252:10-14.
[37] Ex. I-11 (*Pressure Equipment Integrity Incident Investigation*, API RP 585 (1st ed., Apr. 2014)).

forms of "pressure equipment."[38] Blade states that "API RP 585 was developed for Pressure Equipment Integrity Incident Investigation," not gas storage well integrity management and only "presents this as an option that *could* be applied" to gas storage.[39] Further, Blade states that there "are no specific standards or practices related to 'failure analysis or subsequent risk assessment' related to gas storage well casings."[40] We note, however, that while API RP 585 does not apply to gas storage and was not issued until 2014, SoCalGas' practices with respect to investigating well casing issues are consistent with industry standards at the time of the leak.

More importantly, SoCalGas' practices regarding investigation and assessment of well casing failures were consistent with standard practice across the gas storage industry. Minor casing leaks or mechanical issues were inspected running a casing inspection log, determining the location of the leak or issue, and remediating the leak or issues via a well workover. Based on information collected from the casing inspection log and other tests and observations made in the course of the workover SoCalGas was often able to assess the probable cause or causes of the issue. If a pattern of failures developed, (for example erosion from sand production), then a more detailed investigation was conducted and a risk management plan was employed to minimize the potential impact of recurrence. Continuing the erosion from sand production example, SoCalGas routinely conducted sand flow tests to determine critical gas flow rates for sand production in the storage wells.

[38] Note that Blade states that "API RP 585 was developed for Pressure Equipment Integrity Incident Investigation," not gas storage well integrity management and only "presents this as an option that could be applied" to gas storage. See Ex. I-13 at 14 (Blade response to the SED Data Request SED DR-49 at 14). Further, Blade states that there "are no specific standards or practices related to 'failure analysis or subsequent risk assessment' related to gas storage well casings." *See* Ex. I-12 at 13 (Blade Response to SoCalGas Data Request, Feb. 14, 2020, at 13).

[39] *See* Ex. I-13 at 14 (Blade response to the SED Data Request SED DR-49 at 14).

[40] *See* Ex. I-12 at 13 (Blade Response to SoCalGas Data Request, Feb. 14, 2020, at 13).

Where circumstances warranted, SoCalGas performed more extensive investigations. Examples of this include work done to address leaks at wells FF-34A and Frew 3, where SoCalGas observed migration of gas in the subsurface away from the wellbores. SoCalGas' investigations included gas sampling to confirm the source of the leaking gas and analysis of offset wells to determine the extent of gas migration away from the well with the casing leak,[41] as well as construction of numerical simulation models to determine the volume and the areal extent of the leaked gas.[42]

It is important to note that conducting a full Root Cause Analysis, of the sort performed by Blade in connection with the leak at SS 25, is most certainly not industry standard practice. Cutting and extracting the production casing, for direct examination and testing of a failed joint more than thousand feet below ground, is often not feasible. Nor is it reasonable or justifiable to perform such analysis for most casing failures.

It is also critical to note that of the casing failures documented by Blade, which provide the basis for SED's alleged violations, there was no pattern identified that would have led SoCalGas staff to determine that there was any sort of systemic issue that would have indicated that an SS 25 type failure was likely. According to Blade:

> Wells with casing failures were distributed throughout the Aliso Canyon Field. Nothing seems unusual regarding the casing failures near SS-25 when comparing them to the casing failures in the rest of the field. The depths of casing failures ranged from the wellhead to below 8,000 feet, and *no general pattern is apparent*.[43]

Further, Blade stated that "52% of the leaks were between surface and 4,000 ft. with no trend of leak count vs. depth."[44] Finally, Blade stated that "[t]he failure and casing leak rate for

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[41] Ex. I-14 (SCG00195774).
[42] Ex. I-15 (AC_BLD_0033633).
[43] Blade Report at 204 (emphasis added).
[44] *Id*. at 166.

the gas storage wells is around 50%, implying that well age does not correlate with casing failures."[45] All prior well failures had been identified by SoCalGas within a timely manner, were contained locally, and were mitigated properly.

B. Many of the Casing "Leaks" Identified by SED Were Insignificant and Are Irrelevant to What Occurred at SS 25.

SED alleges that:

> "SoCalGas failed to perform failure investigations, failure analyses or root cause analyses on failed Aliso Canyon wells despite more than 60 well casings experiencing leaks, four having parted casings, and several wells having casing corrosion identified."[46] Therefore, SoCalGas lacked important information and background to properly anticipate the extent and consequences of corrosion in its other wells, including well SS-25."[47]

SED's assertion, which is based solely on Blade's report,[48] mischaracterizes 60 well casing issues of varying cause and degree as relevant "leaks." SED's and Blade's assertions appear to be premised on the assumption that these casing issues were somehow similar to the circumstances that led to the failure at SS-25.[49] In fact, Blade's report combines a number of different well conditions as "leaks," including perforations intentionally made by SoCalGas for water shut off tests and stage collar leaks. These well conditions have no relation to corrosion and present little risk or reason for concern. Many of these "leaks" were not even gas leaks, but rather were discovered during the conversion of the field to underground gas storage (when a well was not flowing or holding gas), or initial drilling of a new storage well. Others on the list were either not leaks at all or double or triple counted leaks from the same event.

Blade's list of 63 relevant casing failures incorrectly includes the following:

[45] *Id*. at 204.
[46] SED Opening Testimony at 7.
[47] *Id*.
[48] *See, e.g*., Blade Report at 4.
[49] SED specifically alleges that the alleged lack of follow-up investigation, failure analyses, or root cause analyses of these alleged prior leaks is a "root cause" of the SS-25 incident. *See* SED Opening Testimony at 7.

- Eleven casing leaks (Wells P-12,[50] SS-14,[51] SS-17,[52] P-47,[53] P-25R[54] 4x, FF-35E[55] 2x and SF-2[56]) identified by Blade were actually discovered in wells before SoCalGas operated the field or during initial conversion of the field to underground gas storage. One of these leaks (SS-17) happened in 1952 and occurred during the original drilling of an oil and gas production well by SoCalGas' predecessor.[57] This leak occurred 20 years before the conversion of the field to gas storage and cannot be attributed to SoCalGas storage operations and need not have been investigated by SoCalGas. The other ten leaks that were identified during the conversion to underground gas storage. SoCalGas' identification and remediation of these casing failures simply validates the process that SoCalGas used to inspect and repair, if necessary, all wells prior to putting them into service for gas storage. This is exactly how a conversion process should be performed in a depleted oil or gas field.

- One leak occurred in 1979 (Well MA-1B) during initial drilling and completion operations for new storage wells.[58] This leak, occurring during a pressurization test with nitrogen during drilling,[59] had nothing to do with underground storage operations and was rectified prior to the well ever being put into service for gas storage.[60] Moreover, this leak was much deeper than the leak at SS-25.[61]

- Seven of the casing leaks (Wells FF-32F,[62] SS-25A,[63] FF-32E,[64] P-26B,[65]

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[50] Ex. I-16 (SCG00197973).
[51] Ex. I-17 (AC_BLD_0040033).
[52] Ex. I-18 (SCG00173498).
[53] Ex. I-19 (SCG00134956-SCG00134959)
[54] Ex, I-20 at 138-144, 149 (DOGGR_03700712_DATA_03-20-2008 (Modified 8-18-16).pdf (pp. 138-144; 149)).
[55] Ex. I-21 (SCG00194921-SCG00194926).
[56] Ex. I-22 (DOGGR_03700648_DATA_03-19-2008).
[57] Ex. I-23 (SCG00173498)
[58] Vol. 4, Blade Report at 15; Ex. I-24 (SCG00161941).
[59] Ex. I-25 (SCG00161981).
[60] Vol. 4, Blade Report at 29; Ex. I-24 (SCG00161941).
[61] *Id.* .
[62] Ex, I-26 (DOGGR_03721313_DATA_03-20-2008).
[63] Ex. I-27 (AC_BLD_0001172); Ex. I-28 (DOGGR_03721322 Data_01-20-17.pdf).
[64] Ex. I-29 (SCG00152464); Ex. I-30 (SCG00152567); Ex. I-31 (DOGGR_03721321_DATA_03-20-2008); Ex. I-32 (DOGGR_03721321_FF 32E_WBD_04-04-2019).
[65] Ex. I-33 (SCG00142047-56); Ex. I-34 at 73-74 (DOGGR_03721357_DATA_03-20-2008 (Modified 10-27-2017); p: 73-74); Ex. I-35 (DOGGR_03721357_P 26B_WBD_05-16-2018)

SS-25B,[66] FF-35B,[67] and SS-44A[68]) identified by Blade and forming the basis of seven SED violations were actually leaking stage collars.[69] Stage collars are devices used for multi-stage cementing of production casing in wells.[70] The stage collar is essentially a sliding valve in the casing that can be opened to allow cement to be pumped outside of the casing into the annulus between the production casing and the wellbore. It is quite common for stage collars to not seal completely upon closing the sliding valve after the cementing procedure. This situation is easily remedied with a simple casing repair. More importantly, these stage collar leaks have absolutely nothing to do with corrosion or poor integrity of the casing in the well, and no follow-up investigation or failure analysis is required to determine the obvious root cause of these particular casing leaks, which are common across the entire gas industry.

- One casing leak (Well P-47) identified by Blade was due to incompletely plugged water shut-off holes discovered in 1977.[71] A water shut-off test is a well operation required by DOGGR that involves placing holes in the production casing and then conducting a pressure test (with water or other fluid) to confirm the integrity of the seal created by the cement behind the casing. After the test, the holes have to be cemented and closed. In certain instances, if the holes are incompletely closed and plugged, further work is required to seal the casing. This is standard practice. Water shut-off leaks have absolutely nothing to do with corrosion or poor integrity of the casing in the well, and no follow-up investigation or failure analysis is required to determine the obvious cause of these particular casing leaks of what is a simple mechanical issue.

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[66] Ex. I-36 (AC_CPUC_0000018); Ex. I-37 (DOGGR_03721323_SS 25B_WBD_02-14-2019); Ex. I-38 at 33-34 (DOGGR_03721323_DATA_1-1-2008 (Modified 8-19-16).pdf (pg. 33-34)).
[67] Ex. I-39 at 45 (DOGGR_03721458_DATA_03-19-2008 (Modified 6-13-2016); p. 45).
[68] Ex. I-40 (SCG00177604).
[69] Vol. 4, Blade Report at 25-28, 39.
[70] See Vol. 4, Blade Report at 13 ("The well design included a cement stage collar to pump a two-stage cement job").
[71] Ex. I-41 (SCG00135098).

- A further eight of the casing leaks (Wells F-3,[72] FF-35C,[73] P-32[74] 2x, P-35,[75] SS-4A,[76] P-42C,[77] and Ward-3A[78]) identified by Blade were not leaks at all. These were situations where there was a suspicion of a potential leak, but further investigation by SoCalGas, such as pressure testing or noise logging, confirmed there was no leak to the exterior of the well.[79] Or in the case of F-3 and P-32, SoCalGas discovered holes in an external casing, that had been protected by an inner string during gas operations but the inner string was removed for purposes of the inspection. As such there was no leak. In the case of P-42C there was a hole in the liner top, an internal component of the well.

- Blade's list of casing leaks included four instances (Wells P-32B[80] 2x, SS-4A[81] and MA-5A) of double and triple counting situations where two or more holes in a casing were discovered in a single inspection.[82] These were not separate events, but rather singular investigations discovering multiple proximate holes. These should have only been counted once.

- With regards to the four parted casings alleged by SED (P-45,[83] SS-12,[84] P-42B, and SS-4-0[85]) the circumstances of each of these events, which do not involve corrosion and did not occur in the course of normal operations, are entirely distinct from what occurred at SS 25. As such they did not warrant further investigation.

- The alleged parted casing at P-42B simply does not exist. In 2017 a contractor, in the course of preparing a wellbore diagram for P42B, noted

[72] Ex. I-42 (AC_BLD_0031644); Ex. I-43 (AC_BLD_0031647).
[73] Ex. I-44 (SCG00155950); Ex. I-45 (SCG00155964).
[74] Ex. I-46 (AC_BLD_0067628-AC_BLD_0067629); Ex. I-47 (DOGGR_03700719_DATA_03-19-2008 (Modified 8-18-16).pdf).
[75] Ex. I-48 (DOGGR_03700722_HRVRT_02-26-16 ano II); Ex. I-49 at 32-34 (DOGGR_03700722_DATA_03-19-2008 (Modified 2-28-2018), pp. 32-34).
[76] Ex. I-50 (DOGGR_03721375_Magnetic Flux Leakage Inspection_9-17-2016); Ex. I-51 at 6-9 (DOGGR_03721375_DATA_03-19-2008 (Modified 9-15-2017), pg. 6-9); Ex. I-52 (DOGGR_03721375_SS 4A_WBD_05-16-2018).
[77] Ex. I-53 at 54-59 (DOGGR_03721878 Data_01-20-17 (Modified 5-23-2019), pg. 54-59).
[78] Ex. I-54 at 26-32 (DOGGR_03722306_DATA_03-20-2008 (Modified 10-25-2017), pg. 26-32).
[79] This further goes to refuting SED's allegations that SoCalGas somehow "failed to perform failure investigations."
[80] Ex. I-55 (SCG00146041).
[81] Ex. I-56 (SCG00209334-SCG00209339).
[82] Vol. 4, Blade Report at 24-25, 28-29, 31.
[83] Ex. I-57 (P-45 Well File Excerpts).
[84] Ex. I-58 (SS-12 Well File Excerpts).
[85] *See* SS-4-0 well file at 122, available at https://secure.conservation.ca.gov/WellRecord/037/03722063/03722063%20Data_03-19-08.pdf.

that an anomaly on a 1993 USIT log may indicate either a parted casing or a landing collar.[86] The drilling records from 1979 show installation of a float collar on top of the first three joints of casing at approximately 7490 feet, the same depth as the anomaly noted by the contractor.[87] In addition, P-42B passed the complete battery of tests per Order 1109 including caliper, USIT, HRVRT, and pressure test, with no indication of a parted casing.

- The casing failure at SS-12 occurred in the course of a workover to investigate a potential leak in a threaded connection (which was later determined to be due to a jumped thread, not any sort of corrosion or wall loss). SoCalGas had intentionally cut the casing below the leak point and the casing parted when SoCalGas pulled on the casing to extract it. The fact SoCalGas had run bridge plugs through this area prior to cutting and pulling the casing indicates there was not a part until SoCalGas actually pulled on the casing. In addition, as Blade notes, SoCalGas pulled all the casing joints with Speedtite connections.[88] It is unclear what more SED believes SoCalGas should have done to investigate this event.

- The failure at SS-4-0, as Blade acknowledges, occurred in connection with the 1994 Northridge earthquake, not in the course of normal operations.[89]

- The failure at P-45 occurred in 1969 when Getty Oil owned the well, many years before storage operations. As above it is not reasonable to expect that an operator would investigate discrete isolated failures that occurred years before it owned and operated the field.

In summary, rather than 63 casing "leaks," as alleged by SED, in fact there were less than half that number. There were 32 casing "leaks" documented by Blade which were not leaks at all, were double or triple counted leaks from the same event, or did not occur during the conversion of the field to underground gas storage, initial drilling of a new storage well, routine casing repairs of stage collars, and a water shut-off test. Further, only two of the actual casing leaks documented by Blade (FF-34A and Frew 3) involved situations where gas was known to

[86] Ex. I-59 (DOGGR_03721877_DATA_03-19-2008 (Modified 11-16-2017).pdf).
[87] *See* Ex. I-60 (See 1979 Drilling Record P 45).
[88] Blade Main Report, p. 165, Table 33.
[89] *Id.*

have migrated some distance in the subsurface away from the wellbore.[90]

IV. SOCALGAS USED REASONABLE INDUSTRY PRACTICES TO PREVENT AND MEASURE CORROSION.

SED makes a number of allegations regarding corrosion and the impact of such corrosion on causing the incident. However, SED's allegations appear to be based on misunderstandings, are contradicted by the Blade report or are simply irrelevant to whether or not SoCalGas acted reasonably in operating the Aliso Canyon Facility.

A. Corrosion from Groundwater Did Not Create the Holes on the 11 ¾-Inch Production Casing.

SED alleges that SoCalGas failed to investigate specific corrosion problems at SS-25.[91] Although unclear, SED's testimony appears to assume that the 58 holes in the surface casing were due to corrosion, caused the corrosion and resulting failure on the SS-25 production casing, and could have been identified using the various technologies listed in the statement. SED states that "Blade identified a total of 58 through-wall-metal-loss holes in the 990-foot deep, 11-3/4-inch diameter steel surface casing walls of well SS-25. Fifty of the steel surface casing holes in SS-25 were identified at depths ranging between approximately 150 feet and approximately 195 feet. The through-wall-metal-loss holes were identified using various technologies, including caliper, Ultrasonic Corrosion Imaging (UCI) and High Resolution Vertilog (HRVRT). Camera logging data were consistent with the technology logging data, with photographs matching the sensory logging tools' metal loss locations." This logic is flawed and the allegations are without support.

However, SED's testimony fails to mention that Blade concluded that the incident itself,

[90] In connection with violation 86, SED alleges that the FF-34A well file mentioned exploring potential regional casing corrosion in the southeastern portion of the field for study and issuance of a report, but none was located. We note that SS 25 is in the northern portion of the field and 1.5 miles away from FF-34A.
[91] SED Opening Testimony at 11.

not corrosion, likely caused the holes. While the groundwater may have "accessed" the surface casing and there might have been corrosion on the outside of the surface casing, there is no evidence that this corrosion compromised the integrity of the surface casing. In fact, Blade concluded that the holes found in the surface casing were likely a consequence of the pressure surge caused by the axial rupture of the production casing and, thus occurred post-leak.[92] Since there is no evidence that the integrity of the surface casing led to the SS-25 leak, and since it is very likely that the holes were caused by, and not a consequence of, the incident, the reference to the holes in the surface casing in this section of the SED testimony is irrelevant.

B. There Were and Are No Tools Available to Perform the Kind of Inspections SED Demands.

In connection with violations 83, 84 and 85, related to SoCalGas' alleged failure to discover specific corrosion problems on Well SS-25, SED states that "[c]orrosion was not detected on SS-25 because the seven inch casing wall thickness on the SS-25 had never been inspected."[93] SED further alleges that "[v]arious tools [could have been] run in a well with wireline to measure well thickness along the entire length of the casing or tubing casing. These logs were not run in the seven-inch casing of well SS-25."[94]

The testimony from SED and Cal Advocates implies that various technologies were

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[92] Blade Report at 119. Blade states that "[s]ome of these approximately 58 holes [in the 11 ¾-in surface casing] could have existed prior to the 7 in. casing axial rupture," but that "[m]any of the holes exhibited sharp corners that may have been more typical of a burst failure, implying that they occurred due to a pressure surge in the surface casing."

[93] SED Opening Testimony at 16. It should also be noted that SED's apparent premise underlying this argument is that SoCalGas failed to inspect and identify the 58 holes in the surface casing described above in Section III-A. However, as noted above, Blade determined the holes were most likely caused by the explosion itself. It would likely have been impossible for SoCalGas to have found these holes using any inspection techniques.

[94] *Id.*

available which could have easily identified these holes.[95] This is incorrect. Blade was able to analyze the surface casing and identify the holes only because the production casing had been *cut off and extracted* from the SS-25 well after the incident. Extracting the production casing exposed the surface casing for inspection and examination. During the normal operation of the SS-25 well, the production casing, of course, would have remained cemented in the well.[96] As such, caliper logs, cameras and casing inspection logs would *not* have been able to evaluate the integrity of the surface casing due to the presence of the production casing.[97]

C. <u>SoCalGas had a Sufficiently Reasonable Understanding the Location of the Groundwater and its Relationship to the Well for the Purposes of Safely Operating the Site.</u>

SED alleges 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" until the two groundwater wells were drilled for RCA purposes.[98] However, such an understanding of groundwater depth is only relevant and necessary when initially drilling the well and SoCalGas had the information on groundwater necessary for the continued operation of the well.

Much of the SED testimony focuses on the surface casing in the SS-25 well. However, as discussed above, there is no conclusive evidence that groundwater or corrosion created any

[95] *See* Public Advocates Office Opening Testimony at 3-4, 6-7. In fact, CA Advocates openly states that SoCalGas would have been able to identify corrosion as far back as 1988. *Id.* at 9 ("Had SoCalGas' management properly administered the [1988] program, the corrosion issues on SS-25 would have been timely identified."). This is directly contradicted by the Blade Report which states "[i]t is not possible to determine what an inspection of the SS-25 casing would have shown in 1988." Blade Report at 204.

[96] As discussed in detail below in Section VII, this kind of workover requires a substantial amount of work and is dangerous.

[97] Notably, SED's witness testified that she had never dealt with inspection logs in a gas storage field and that she has never been present when an inspection log was run. *See* Ex. I-10 at 65:10-15 and 66:19-20 (Felts Depo. Tr., 65:10-15 and 66:19-20).

[98] SED Opening Testimony at 39.

holes in the surface casing. Additionally, both the Blade Report and the SED testimony present a figure which shows the groundwater entering the annulus of the 7-inch production casing and the wellbore below the depth of the surface casing.[99] Thus, the postulated mechanism by which the groundwater accessed the annulus of the 11 ¾ inch surface casing and the 7 inch production casing is via ingress below the surface casing shoe where the production casing is not cemented and then mixing with the fluids outside the production casing which extend upwards into the annulus between the production casing and the surface casing.

This is important because, as acknowledged by Margaret Felts in her deposition, "[a]nybody 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."[100] The SS-25 well was drilled in late 1953 and early 1954 by Tidewater Associated Oil Company. At the time that Tidewater drilled the well, they would have set the 11 ¾ inch surface casing at a depth reviewed and approved by the DOGGR, which was below all known shallow groundwater sources based upon local hydrogeology.[101]

The purpose of surface casing is to isolate freshwater strata so that they are not contaminated during the drilling and completion of a well. Surface casing is not designed to prevent oil and gas from escaping the well and getting to the surface. SoCalGas took over operation of the SS-25 well during the conversion of the Aliso Canyon field to gas storage. This is not uncommon. Of the approximately 400 gas storage fields in the U.S., roughly 80% are in depleted fields that originally were developed to produce oil and gas. Thus, conversion of older

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[99] *See* Blade Report at 100; SED Opening Testimony at 43.
[100] Ex. I-10 at 251:17-20 (Felts Depo. Tr., 251:17-20). However, Ms. Felts goes on to note that beyond that general statement, she does not know what practices at other gas storage facilities are (she does not know what industry standard is). *Id.* at 251:24-25.
[101] See SoCalGas Reply Testimony Chapter VII (Neville), noting that DOGGR set the presumed groundwater level at the time of drilling.

oil and gas wells is a common industry practice.

Given that the purpose of the surface casing is to protect groundwater zones during the initial drilling and completion of the well, which was done in 1953 and 1954, and that the oversight of the surface casing operation was reviewed and approved by the DOGGR, there really is no reason for SoCalGas to have a "reasonable understanding of the groundwater depths relative to the surface casing shoe and production casing of well SS-25" as is alleged by in the SED testimony.[102] Moreover, it is not standard practice for gas storage operators to assess water depths relative to the wellbore after the surface casing has been set.

Once SoCalGas took over operation of the SS-25 well, there was no way for them to conduct an evaluation of the integrity of the surface casing. The surface casing was cemented in the wellbore. The production casing was inside of the surface casing and was also cemented. At the time of the conversion of the Aliso Canyon field to gas storage in the 1970's, and even in 2015 at the time of the SS-25 incident, the casing inspection logging tools used by the gas storage industry could only evaluate a single string of pipe. It was not possible to evaluate the integrity of the surface casing by running the logging tool down inside the production casing string.

Based on the historical data in the Aliso Canyon field, there was no reason for SoCalGas to anticipate there might be a potential problem with corrosion of the production casing at a

[102] Notably, in response to discovery questions relating to the laws, regulations and industry standards underlying this allegation, SED responded that "[g]ood completion practices include the use of drilling mud with an alkaline Ph [sic]; 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." SED then cites to an alleged industry standard. However, as stated above, the knowledge of groundwater location is relevant to the initial drilling – this is where completion practices would come into play as well. Such practices are *irrelevant* to the ongoing operation of the well. *See* Ex. I-9 (SED Supplemental Data Response to SoCalGas Data Request 3 (as supplemented Jan. 23, 2020), SED response to 9(b)). Additionally, Blade noted that it did not identify any industry standards, laws or other regulations that required such an "understanding of groundwater depth" as demanded by SED. *See* Ex. I-61 (Blade Response to SoCalGas Data Request, Jan. 9, 2020, Response to Questions 1b, 1c and 1d).

depth above the surface casing shoe inside the annulus between the production casing and the surface casing, as occurred in the SS-25 well. Blade investigated the occurrences of shallow corrosion throughout the field. Regarding the 27 wells they identified that demonstrated shallow corrosion, Blade determined that almost all of the wells had production casing external corrosion present below the surface casing shoe. Excluding the SS-25, only one well, P-50A, had production casing external corrosion above the surface casing shoe.[103] Thus, corrosion on the production casing above the surface casing shoe was very rare.

SED's allegations that SoCalGas is at fault for failing to employ a reasonable understanding of the groundwater depths relative to the surface casing shoe and production casing of the SS-25 well are unsupported. Knowledge of the hydrogeology and groundwater is only relevant for the design and implementation of the surface casing.[104] This was done almost 20 years prior to SoCalGas taking over operations of the SS-25 well and was done with DOGGR approval. Moreover, DOGGR established the levels to assume for the base of freshwater at Aliso. There was no reason for SoCalGas to expect or anticipate possible corrosion of the production casing above the surface casing shoe because historically, prior to the SS-25 incident, it had only happened once and was very rare. Further, the production casing in the well had been installed and cemented consistent with the industry standards of the U.S. gas storage industry at the time of installation.

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[103] Blade Report at 189.

[104] Ms. Felts appears to confirm this in her own testimony, where she agrees that "it would be necessary to have an understanding of groundwater depths for purposes of setting the surface casing." Ex. I-10 at 254:1-5 (Felts Depo. Tr. 254:1-5). As stated above, the surface casing was set when the well was installed.

D. <u>Corrosion of the Surface Casing did not cause Corrosion in the Production Casing and the Surface Casing is not Intended as a Gas Barrier.</u>

SED argues that SoCalGas violated Section 451 because it did not "understand the consequences of corroded surface casings."[105] However, it is interesting to note that nowhere in their testimony does SED indicate what the consequences were of external corrosion of the surface casing in the SS-25 well.[106] In other words, SED faults SoCalGas for not understanding the consequences of corroded surface casing, yet they do not offer an explanation of what those consequences were.

Further, SED makes no mention in their testimony of any link or connection between corrosion of the surface casing in the SS-25 well and the rupture in the production casing of the well which caused the leak. As was stated in Section IV-A, *corrosion in the surface casing did not provide the ingress for groundwater to access the production casing at the point of the leak*.[107] Instead, this was caused by groundwater entering the wellbore opposite the uncemented production casing below the surface casing shoe. This is a completely different issue and will be discussed further below.

The Blade report also correctly points out that "[t]he function of the surface casing is to isolate fresh water sources and also provide a string for drilling the deeper hole for gas storage or oil production. The surface casing is not intended to provide any further barriers to gas or oil."[108] Thus, SoCalGas cannot be faulted for the condition of corrosion on the surface casing

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[105] SED Opening Testimony at 47.

[106] Further, SED's follow-up answers to discovery state the same – alleging serious consequences but merely stating that corrosion will occur. *See, e.g.*, Ex. I-9 (SED Supplemental Data Response to SoCalGas Data Request 3 (as supplemented Jan. 23, 2020), SED response to question 9(a)).

[107] Felts acknowledges this in her deposition, where she states that she does not contend that the corrosion of the surface casing was the point of entry for the water that caused corrosion at the SS-25 production casing. *See* Ex. I-10 at 241: 10-17 (Felts Depo. Tr. 241:10-17).

[108] Blade Report at 192.

and any escaping gas through holes in the surface casing, which were caused post-leak,[109] because the purpose and objective of surface casing is not to provide a barrier to gas or oil leaving the wellbore.

E. <u>The Production Casing was Cemented Properly pursuant to Industry Standard Practices.</u>

SED alleges that SoCalGas violated Section 451 because it "did not understand the consequences of uncemented production casings."[110] Based on our experience, in the 1970's, when many of the Aliso Canyon wells were completed or converted for gas storage, it was not industry standard for underground gas storage wells to have the production casing cemented to surface. Rather, it was common practice that the production casing was cemented in a fashion such that the storage reservoir was isolated and cement extended above the storage zone for several hundred to a few thousand feet. This was the case in the SS-25 well where the top of cement was approximately 1,500 feet above the gas storage reservoir interval.

Of the 31 U.S. states with gas storage operations in October 2015, only six states had added requirements that production casings on existing, retrofitted wells be cemented to surface. California was not one of those states. In addition, it is not practical nor prudent to attempt to remediate a well by attempting to squeeze cement behind the production casing in those areas where the well was originally not cemented. The amount of damage caused to the casing would far outweigh any potential benefit of such remedial work.

With respect to the quality of the cement behind the surface casing, during the original well drilling operations in 1953 and 1954, attempts were made to cement the 11 ¾ - inch surface casing from 990 feet to the surface. However, during the cementing operations, no cement was returned to the surface indicating an incomplete cementing job. Thus, two top cement jobs were

[109] See Section IV, infra.
[110] SED Opening Testimony at 47.

performed where cement is pumped from the surface down behind the surface casing to fill the annulus with cement up to the surface. This is a typical, industry standard operation when there are no surface returns, as was the case in the SS-25 well.

It is important to note that for most gas wells, the quality and completeness of cement behind the surface casing is unknown. The only indication that a surface casing cement job is satisfactory is whether or not cement is returned to surface. It is not customary, and it is considered unnecessary, to run a cement bond log on surface casing. Surface casings are not designed to be a barrier to oil and gas escaping the wellbore. Therefore, in cases such as this one where cement does not return to surface, it is industry standard practice to remediate the problem by augmenting the cementing procedure with one or more top cement jobs. This is exactly what was done in the drilling and completion of the SS-25 well.

Prior to 1990, cementing of the production casing in gas storage wells to the surface was not industry standard. Rather, the industry standard and common practice was that the production casing was cemented in a fashion such that the storage reservoir was isolated and cement extended above the storage zone for several hundred to a few thousand feet. This was the case in the SS-25 well.

F. <u>Cathodic Protection is not Industry Standard and Was Not Necessary for SS-25.</u>

SED alleges that "[c]athodic protection systems are commonly used to protect pipelines from corrosion" and goes on to imply that SoCalGas is in violation of Section 451 for not employing cathodic protection on SS-25.[111] However, cathodic protection is not the industry standard for gas storage wells.

The gas storage industry remains divided as to the effectiveness of cathodic protection

[111] SED Opening Testimony at 45-47.

systems for storage wells. While it is recognized that there are certain localized conditions where such a system can be beneficial, for most gas storage wells, the benefits of cathodic protection system are questionable. As a result, cathodic protection of surface casing in gas storage fields is not an industry standard practice.

The SED faults SoCalGas for not having installed cathodic protection to prevent corrosion of the surface casing in the SS-25 well. What the SED testimony does not mention; however, are the limitations and downsides of using cathodic protection in a gas storage field such as Aliso Canyon. Cathodic protection can be an effective tool to prevent corrosion in shallow surface casing strings. While not an industry standard, the technology is used in some gas storage fields with known areas of high corrosion. Recall that, Aliso Canyon is not one of these areas; the Blade report documented finding no pattern of corrosion associated with well age, well location, or depth. Thus, given that the SS-25 well is not in a corrosion "hot spot," the operator must balance the limited benefits of using cathodic protection to shield the surface casing versus the potential limitations and downsides.

In areas of high well density, such as the three-well pad at the SS-25 location where wells are located within a few hundred feet of one another, the application of cathodic protection is complex and problematic. If the induced currents are not properly balanced, well casings that are not receiving adequate current will be unprotected and through oxidation reactions will actually see increased corrosion and casing leaks, above what would have occurred with no cathodic protection. In these situations, corrosion of surface casings is actually increased rather than prevented.

Similarly, within the areal "footprint" of a cathodic protection system, all wells must be protected. The Aliso Canyon field is not only a gas storage field, but there are non-storage operations within the field boundaries accessing shallower hydrocarbon production. These shallow wells are not operated by SoCalGas. If SoCalGas were to install cathodic protection only on its gas storage wells, any shallow hydrocarbon wells operated by others at the field would suffer increased corrosion and loss of well integrity because of the cathodic protection currents.

Cathodic protection typically works very well on protecting surface pipelines or shallow gas gathering lines, where the resistivity of the environment around the steel is known and relatively uniform. However, in the case of vertical surface casing which extends to a depth of approximately 1,000 feet, such as the SS-25 well, the resistivity of the soils can change suddenly and dramatically with variations in depth. This results in an extremely difficult engineering solution to design a cathodic protection scheme that accounts for the rapid changes in soil resistivity and balances the current applied in the cathodic protection system. When multiple wells are added to the equation, such as would be the case around the SS-25 well pad, the problem becomes increasingly more difficult and complex. Any imbalance in the applied current will have the undesired effect of increasing corrosion.

Finally, the axial rupture of the production casing occurred at a depth of 892 feet, which was inside the surface casing of the well. The Blade report clearly states, "While a cathodic protection system would have provided corrosion protection to the 11 ¾ in. casing, it would not have protected the 7 in. casing inside the 11 ¾ in. casing."[112] Thus, an independent corrosion protection mechanism like cathodic protection would not have been useful in this case, contrary to the suggestions made in the SED testimony.

[112] Blade Report at 215.

V. SOCALGAS HAD WELLBORE INTEGRITY MANAGEMENT PROGRAM BEFORE THE INCIDENT THAT MET OR EXCEEDED INDUSTRY STANDARD PRACTICES.

SED's Opening Testimony alleges, "SoCalGas did not have any form of risk assessment focused on wellbore integrity management, including lack of assessment of qualitative probability and consequence of production casing leaks or failures."[113] SED further criticizes SoCalGas for not initiating a storage integrity management program in 2009, even though such a program was recommended by Mr. James Mansdorfer, who was the Storage Engineering Manager at the time.[114] Lastly, SED faults SoCalGas for relying upon temperature and noise surveys for monitoring the casing integrity of gas storage wells at Aliso Canyon. Based on our review of the records and evidence, SED's assertions (which are the basis for asserted violations 74, 75 and 78) are unfounded.

First, prior to 2007 SoCalGas did assess risk as part of ongoing operations, even if it was not documented as a formal risk assessment program; this was consistent with the standard practices of other operators.[115] Second, starting in 2007 SoCalGas had a risk assessment program, which focused on wellbore integrity management. SoCalGas implemented a "Replace and Inspect" initiative, which included conducting wellbore integrity evaluations at Aliso Canyon and performing remedial work, if necessary, based on the results. SoCalGas implemented the initiative two years prior to Mr. Mansdorfer's 2009 recommendation for a similar initiative. The initiative included the inspection of the integrity of the production casing in the storage wells. Moreover, the "Replace and Inspect" initiative included detailed evaluations

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[113] SED Opening Testimony at 12. Interestingly, SED testimony within Section 2 makes no further mention of this allegation.
[114] Note that SED's testifying expert, Margaret Felts, under oath, stated that she had never spoken or met Mr. James Mansdorfer. Ex. I-10 at 221:10-14 (Felts Depo. Tr., 221:10-14). Instead, she relied on Mansdorfer's EUO and some produced documents from Mansdorfer or SoCalGas. *Id.* at 221:15-25.
[115] *See, e.g.*, Ex. I-62 (Testimony of Phillip E. Baker, Southern California Gas Company, 2016 General Rate Case, A-14-11-004 at PEB-5 – PEB-8).

of the wellbore integrity and replacement of well hardware equipment, such as wellhead valves and the well tubing and packer. As a result of this initiative, SoCalGas permanently removed six wells, of approximately 30 wells inspected, from service based on their downhole condition.

Second, in 2014, SoCal Gas improved upon the "Replace and Inspect" initiative by developing the Storage Integrity Management Program ("SIMP"). SoCalGas was in the process of initiating the SIMP at the time of the SS-25 incident. For gas storage wells, SIMP includes threat identification and risk assessment based on a variety of factors, remediation as necessary, development of preventative and mitigative measures, and record-keeping requirements. Essentially, SIMP combines risk management and integrity management into an aggressive integrity management program that addresses risk more proactively.[116]

The SIMP is consistent with the API RP 1171 recommended practice for well integrity evaluation. As explained above, API RP 1171 contemplates being implemented in 7-10 years and was not published until September 2015, shortly before the incident.[117] Moreover, SoCalGas' SIMP is similar to initiatives other gas storage operators were contemporaneously implementing. It is our experience that, historically, operators in the gas storage industry performed well integrity work responsively due to technological limitations as well as general success with the approach of remediating as issues arose. Recently, some operators are beginning to utilize improved technology to evaluate the condition of downhole equipment before failure occurs.[118] While SoCalGas' efforts, the "Replace and Inspect" initiative and SIMP

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[116] For example, Ravi Krishnamurthy from Blade described SoCalGas' SIMP program as being "intense." Ex. I-63 at 340:7-15 (Krisnamurthy Depo. Tr. 340:7-15).
[117] Ex. I-8 (Underground Natural Gas Storage Integrity & Safe Operations 4 (July 6, 2016), available at https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/underground-natural-gas-storage/59336/aga-white-paper-ungs-integrity-and-safe-ops-20160706.pdf).
[118] For example, SoCalGas has already notified SED and others that part of its SIMP program involves the prioritization of wells. *See* Ex. I-64 (SoCalGas Response to SED Request, Question 2, Received Feb. 4, 2016, Responded Feb. 16, 2016). (Providing a list of priority wells at Aliso Canyon).

place them among the pioneers in the industry, moving towards a new, more proactive approach to well integrity management, they are really just formalizing risk assessment processes that were already in place, albeit informally.

Third, SED's criticisms are rooted in the benefits of hindsight. While SED faults SoCalGas for relying on temperature and noise surveys, it also acknowledges that DOGGR fully approved SoCalGas's casing integrity monitoring program.[119] At the time of the SS-25 incident, only two states (out of 31 with gas storage operations) required corrosion testing through vertilog or similar casing inspection tools; of those two states, only one had significant gas storage operations. Further, only 10 of those 31 states required *any* periodic mechanical integrity testing on gas storage wells with tubing and packer completion.[120] While not controlling, because California was one of the states with requirements, this statistic is indicative of the progress in the industry. Therefore, SoCalGas was following DOGGR requirements and exceeding national standards by conducting annual temperature surveys on all Aliso Canyon storage wells.

VI. DUAL MECHANICAL BARRIERS ARE NOT INDUSTRY STANDARD AND SINGLE BARRIER WELL COMPLETIONS ARE INDUSTRY STANDARD.

In their Opening Testimony, SED asserts that 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.[121] SED found "that SoCalGas violated Section 451 by operating well SS-25 without a backup mechanical barrier to the 7-inch production casing."[122]

While it is correct that SoCalGas did not have a dual mechanical barrier system in the

[119] Ex. I-5 (DOGGR Project Approval Letter, April 18, 1989; revised July 26, 1989). SED acknowledges that DOGGR has primary jurisdiction over down hole gas storage and gas storage wells. Ex. I-10 at 235 (Felts Depo. Tr., 235).
[120] California required periodic mechanical integrity testing and approved the use of temperature logs and noise logs, as needed to meet this requirement.
[121] SED Opening Testimony at 18.
[122] SED Opening Testimony at 25.

wellbore of SS-25,[123] a dual barrier well design in underground gas storage has never, including through today, been considered the industry standard practice.[124] In its opening testimony, SED fails to identify an industry standard requiring a dual mechanical barrier system. As stated by a JITF report, *Underground Natural Gas Storage – Integrity & Safe Operations* ("JITF Report"), "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."[125] The JITF Report goes on to state that "10-25 percent of natural gas storage wells have a full tubing string set into an isolation packer."[126] JITF later revised this figure to 13 percent of natural gas storage wells.[127] Thus, Aliso Canyon's single barrier well completion were consistent with the industry standard and approximately 87% of all gas storage wells in operation in the U.S.[128]

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[123] At the time of conversion of the Aliso Canyon field to gas storage operations, the injection/withdrawal wells were designed with tubing on a packer and an installed subsurface safety valve ("SSSV"). The wells were operated in a single barrier configuration, utilizing annular flow to achieve the high flowrates necessary for storage operations. By flowing gas in the annulus between the tubing and production casing, effectively only a single barrier, the production casing, existed between the storage gas and the surrounding strata in those parts of the well where the production casing was not cemented.

[124] It is important to note that DOGGR's regulations requiring dual mechanical barriers (Cal. Code Reg. § 1726.5(b)(1)) are only mandated to be in place "within seven years" of the effective date of the regulations, which is not until October 2025. Cal. Code Reg. § 1726.3(d)(1). Additionally, Margaret Felts, SED's testifying witness, stated that she did not "know what technology is used in the wells in other storage fields around the United States" and that she had not "looked into that." Ex. I-10 at 236:23 – 237:1 (Felts Depo. Tr., 236-37:23-1).

[125] Ex. I-8 (Underground Natural Gas Storage Integrity & Safe Operations 21 (July 6, 2016), available at https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/underground-natural-gas-storage/59336/aga-white-paper-ungs-integrity-and-safe-ops-20160706.pdf).

[126] *Id.* at 55.

[127] Note the range was updated by JITF in September 2016 according to a poll of U.S. Underground Natural Gas Storage Operators Ex. I-6 at 13 ("Tubing and Packers in Underground Natural Gas Storage: Safety and Reliability Considerations", AGA/API/INGAA Underground Natural Gas Storage Joint Industry Task Force, September 16, 2016, Slide 13). This estimate represents an 80% response rate (13,485 out of a total of 17,500 storage wells). *Id.* .

[128] *Id.* Ex. I-8.

VII. SOCALGAS' PROGRAM FOR THE INSPECTION AND MEASUREMENT OF WALL THICKNESS WAS COMPLIANT WITH REGULATIONS AND MET INDUSTRY STANDARDS.

SED asserts, in connection with violation 78 that, "SoCalGas did not have internal policies that required inspection and measurement of the wall thickness of wellbores at Aliso. Instead, SoCalGas used techniques that detected and fixed leaks only after the event occurred."[129] SED testimony also notes, "SoCalGas had no internal policies on wall thickness inspections because the company assumed that regulatory compliance was being adhered to by running annual temperature surveys in accordance with the Aliso Canyon Monitoring Plan and the project approval letter dated 1989 requiring an annual mechanical integrity test (MIT)."[130]

First, SED is incorrect that SoCalGas "assumed that regulatory compliance was being adhered to through the running of annual temperature surveys." DOGGR approved SoCalGas's monitoring program as being in regulatory compliance.[131] Further, as already noted, the SoCalGas monitoring program met and exceeded industry standards.[132]

Second, SED's testimony creates the inference that SoCalGas could have, and should have, done better than simply running temperature surveys and periodic noise logs. The SED testimony faults SoCalGas for not also running casing inspection logs. However, SED criticism directed at SoCalGas's policies and practices is myopic and ignores the lessons learned by the gas storage industry over the past 60+ years.

Running a casing inspection log in a well, such as the SS-25 well at Aliso Canyon,

[129] SED Opening Testimony at 25.
[130] SED Opening Testimony at 25-26.
[131] *See* Blade Report at 216 ("The 2015 DOGGR regulations required periodic MITs, and annual temperature surveys were approved to meet the MIT requirements."). *See also Id.* at 202 (noting that DOGGR "approved the use of static temperature surveys to satisfy compliance of the requirements for mechanical integrity."
[132] Moreover, Blade has stated that it did not identify any industry standards "in connection with internal policies requiring production casing wall thickness inspections." Ex. I-12 at 6 (Blade Response to the SoCalGas Data Request January 23, 2020 (Feb. 14, 2020) at 6).

necessarily requires conducting a workover on the well. A workover entails killing the gas production from the well by filling the wellbore with fluid and then pulling all of the tubing out of the wellbore. Only after all this is done may a gas storage operator run a casing inspection log in the well. It was not possible to evaluate the integrity of the production casing by running the logging tool down the tubing string. Therefore, to accomplish what the SED testimony suggests should have been done, which is to run casing inspection logs in wellbores that had historically given no indication of problems with the production casing, it would have been necessary to run a workover on the well.

The JITF Report contains a detailed discussion of the risks of workovers in Section 2 of their document titled, "Lessons Learned from Historical Underground Natural Gas Reservoir Storage Well Events (API 1171 Sections 8.4 and 8.7)."[133] The JITF Report analyzed 61 unplanned storage well releases of gas in the U.S. between 1953 and 2010.[134] Their analysis showed that approximately a third of the 61 incidents on record happened during well interventions, including well workovers or re-works. The JITF Report further notes that the industry statistics show the likelihood of such an unplanned release event occurring in a gas storage well is classified as "very unlikely" to "extremely unlikely" or "remote". Thus, it is significant that approximately a third of such incidents occurred during well workovers.

For example, three workers recently died (and a fourth was injured) during a workover

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[133] Ex. I-8 at 9-11 (Underground Natural Gas Storage Integrity & Safe Operations 21 (July 6, 2016), available at https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/underground-natural-gas-storage/59336/aga-white-paper-ungs-integrity-and-safe-ops-20160706.pdf).

[134] Ex. I-8 at 10 (Underground Natural Gas Storage Integrity & Safe Operations 10 (July 6, 2016), available at https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/underground-natural-gas-storage/59336/aga-white-paper-ungs-integrity-and-safe-ops-20160706.pdf).

operation at a well in Burleson County, TX.[135] The investigation is ongoing but it is believed that an "unexpected amount of natural gas entered the well and ignited. What caused the ignition remains under investigation."[136] A similar incident occurred in Watford City, North Dakota in 2016, where one worker was killed and three seriously injured when an amount of gas entered the well during a workover and ignited.[137] A 2017 report by the Centers for Disease Control and Prevention and the National Institute for Occupational Safety and Health found that 9 fatalities occurred in 2014 during well workovers and that "rig or equipment repair and maintenance" was one of the activities "most commonly associated with fatalities."[138]

U.S. gas industry experience mirrors the JITF Report's findings that *the most likely time to have an accident or an incident on a well is during a workover*. Anytime a gas storage operator pulls a pipe out of a well, such as when removing tubing to run a casing inspection log, the chance of an incident increases dramatically.

In their 2016 presentation, the JITF noted the following safety risks and dangers of running casing inspection logs in a gas storage well:

- Advanced tools such as high resolution Vertilog cannot be used to analyze the

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[135] *See* Ex. I-65 (Liz Hampton, *Chesapeake Energy, others sued for $1 million in fatal Texas oil-well blast*, REUTERS U.S. LEGAL NEWS (Feb. 2, 2020), available at https://www.reuters.com/article/us-chesapeake-enrgy-blowout-lawsuit/chesapeake-energy-others-sued-for-1-million-in-fatal-texas-oil-well-blast-idUSKBN1ZZ2P1) (noting that the blowout occurred during a workover operation); *see also* Ex. I-66 (Jerry Bohnen, *Federal agencies probe Chesapeake well blowout that killed 3 workers in Texas*, OK ENERGY TODAY (Feb. 5, 2020), available at http://www.okenergytoday.com/2020/02/federal-agencies-probe-chesapeake-well-blowout-that-killed-3-workers-in-texas/) (noting the death of the third worker).
[136] Ex. I-67 (*Feds to Probe Fatal Chesapeake Energy Oil Well Accident*, ROUGHNECK NEWS (Feb. 4, 2020), available at https://www.roughneckcity.com/roughneck-city/oilfieldnews/1415/feds-to-probe-fatal-chesapeake-energy-oil-well-accident).
[137] Ex. I-68 (Amy Dalrymple, One Killed, Three Injured in Well Site Accident, Williston Herald (June 20, 2016), available at https://www.willistonherald.com/news/one-killed-three-injured-in-well-site-accident/article_e90d2b4c-3713-11e6-98b4-0fe09945798a.html).
[138] Ex. I-69 (SOPHIA RIDL ET AL., CENTERS FOR DISEASE CONTROL AND PREVENTION & NATIONAL INSTITUTE FOR OCCUPATIONAL SAFETY AND HEALTH, OIL AND GAS EXTRACTION WORKER FATALITIES 2014 12-14 (Aug. 2017)).

condition of the casing when tubing is present. Thus, a workover is required.

- The greatest risk for an accident is during intervention or workover.
- Packer slips apply thousands of pounds of force into the casing and leave indentations in the pipe wall.
- Scale and ovality allow gas to leak around the packer.[139]

Therefore, there is a very good reason why the gas storage industry standard for monitoring casing integrity, in wells with tubing and packer completion, at the time of the SS-25 incident was to use temperature surveys rather than the more aggressive strategy of conducting well workovers so that casing integrity logs could be run.[140] Given the safety risks associated with well workovers JITF identified, it is often not the best course of action for a gas storage operator to run a workover on their well when there is no reason to suspect there might be a problem with that well, as was the case with SS-25. To do so only increases the risk and likelihood of an unplanned release of storage gas.

VIII. SOCALGAS' PRESSURE MONITORING SYSTEM WAS REASONABLE AND THE CHANGES SED DEMANDS WOULD NOT HAVE MADE ANY DIFFERENCE.

SED asserts, in connection with violation 87 that "SoCalGas lacked a real-time, continuous pressure monitoring system for well surveillance, which prevented an immediate identification of the SS-25 leak and accurate estimation of the gas flow rate."[141]

SED's testimony regarding real time pressure monitoring ("RTPM") is unclear. At deposition, SED's witness clarified that the reason RTPM was important was that it could have enabled SoCalGas to identify and remediate the leak at SS-25, which she believes had been

[139] Ex. I-6 at 6 ("Tubing and Packers in Underground Natural Gas Storage: Safety and Reliability Considerations", AGA/API/INGAA Underground Natural Gas Storage Joint Industry Task Force, September 16, 2016, Slide 6).
[140] It is also important to note that SED's sole witness, Margaret Felts stated that she had "never been present when a log was run on an oil or gas well." Ex. I-10 at 66:19-20 (Felts Depo. Tr., 66:19-20).
[141] SED Opening Testimony at 47.

present for years, at an earlier point in time.[142] The facts, however, are otherwise: the leak and failure at SS-25 was a sudden event and there was no pre-existing leak. Ms. Felts testimony on this issue is also inconsistent with Blade's report. As such, SED's contention here is simply without any factual basis or support.

Ms. Felts also appears to be arguing separately that RTPM would have provided flow rate data that could have been utilized in the well kill.[143] As a general matter, SED's allegations regarding real time pressure monitoring, and the Blade analysis on which it appears to be based, are highly speculative.

A. Real-Time Pressure Monitoring Systems Are Not Industry Standard in Gas Storage Fields.

A real-time continuous pressure monitoring system, as discussed in the SED testimony, is also known as Supervisory Control and Data Acquisition, or SCADA. The SED testimony in this section is critical of SoCalGas for not having a SCADA system in place at Aliso Canyon at the time of the SS-25 incident. However, installing SCADA on existing gas storage wells was not an industry standard practice in the U.S. gas storage industry in October 2015. Notably, both Blade and SED's expert witness stated that they did not identify any industry standards or regulations that required real-time, continuous pressure monitoring for well operations.[144]

Without a communication link to each wellhead, there was virtually no opportunity for remote control, much less data monitoring. The Interagency Task Force on Natural Gas Storage

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[142] *See* Ex. I-10 at 267:15-25, 268:8-16, 269:22-24 (Felts Depo. Tr. 267:15-25, 268:8-16, 269:22-24).
[143] *See, e.g.*, Ex. I-10 at 270:15-272:1 (Felts Depo. Tr. 270:15-272:1).
[144] SED's expert testified that she was unaware of and had not looked into industry standard practice regarding continuous pressure monitoring in gas storage fields. Ex. I-10 at 266:1-5 (Felts Depo. Tr. 266:1-5). *See also* Ex. I-12 at 7-8 (Blade Response to SoCalGas Data Request, Feb. 14, 2020, Response to Questions 2a and 2b (pp. 7-8)) (Blade states that it "did not identify any INDUSTRY STANDARD(S) 'related to real-time, continuous pressure monitoring systems for well surveillance.'" Blade similarly did not identify any laws or regulations requiring real-time, continuous pressure monitoring).

Safety notes that 80% of all storage wells within the industry were drilled prior to 1980 and thus did not have a communication link.[145] Thus, in order to have remote control or data monitoring, storage operators would have to retrofit old wellheads with expensive electronic data recorders. It wasn't until gas storage compressor stations became more automated and had fully functional computer networks and SCADA systems, that operators began to extend communications capabilities to individual wells. It wasn't until the early 2000's that remote data capture equipment started to be installed on wellheads so the operators could download pressure and temperature data periodically, typically weekly, to their laptops. Our experience indicates that even today less than half of all gas storage operators have full SCADA capability. New regulations issued after the SS-25 incident will likely accelerate installations, but they have been slow coming.[146]

Most gas storage operators now have SCADA systems for their compressor station(s) and central control facility operation, but as of 2015 very few gas storage fields that were developed in depleted oil or gas fields had retrofitted their storage wells with this capability.[147] SoCalGas was in this same position at Aliso Canyon having a SCADA system for their central facilities, but not for monitoring individual well data. At the time of the SS-25 incident, SoCalGas had purchased and was in the process of installing SCADA for their wells at each of their gas storage facilities, but the system at Aliso Canyon had not yet been installed.

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[145] Ex. I-70 (Ensuring Safe and Reliable Underground Natural Gas Storage – Final Report of the Interagency Task Force on Natural Gas Storage Safety, October 2016).
[146] Ex. I-71 (See https://inductiveautomation.com/resources/article/what-is-scada).
[147] Notably, SED's witness testified that she had not looked at industry standards for continuous pressure monitoring in gas storage operations *at all*. *See* Ex. I-10 at 266:1-5 (Felts Depo. Tr. at 266:1-5).

B. Real-Time Pressure Monitoring Would Neither Have Provided a Meaningfully More Immediate Identification of the Leak, Nor Would It Have Provided Insight into the Extent of the Leak.

The SED testimony states the following:

"The lack of real-time pressure measurements prevented the immediate identification of the SS-25 7-inch casing failure."[148] SED further states that "[i]f this type of system had been installed on SS-25, it would have provided insight into the time of the leak, the opportunity to shut in the well immediately, size of the leak, and the extent of the problem."[149]

The above SED statements, which are copied directly from the Blade report with no further comment, analysis or insights, are incorrect and irrelevant. SED alleges that if a SCADA system were installed, it would have provided insight into the time of the leak and the opportunity to shut-in the well immediately.[150] That SoCalGas could have somehow stopped the failure mid-rupture is pure speculation, lacks factual support, and belies credulity.[151] Blade estimates the time of the leak at between 7am and 8am on October 23, 2015.[152] SoCalGas discovered the leak at 3:15pm that same day, and shut-in the well by 3:30pm that same day. For all intents and purposes, SoCalGas, through their regular well monitoring, discovered the leak and shut-in the well almost immediately. A few hours difference in the initial identification of the gas leak and the closing of the well would have made absolutely no difference to the actions

148 SED Opening Testimony at 48.
149 *Id.*
150 SED's witness says the same in her deposition, where she stated that "[SoCalGas] 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 the leak before it actually broke out the surface . . ." Ex. I-10 at 267: 15-21 (Felts Depo. Tr. 267:15-21). However, she appears to be relying solely on the Blade Report when giving this testimony. *See Id.* at 266:24 – 267:2.
151 SED's expert appears to believe that continuous monitoring would have allowed SoCalGas to identify the leak at an earlier stage when it was a "smaller leak," which would have made dealing with it easier. Ex. I-10 at 268:21 – 267:1 (Felts Depo. Tr. 268:21 – 267:1); *see also Id.* at 271:19 – 272:1. There is no evidence to support this, especially given how rapidly Blade explained the crack in the casing propagating. *See* Blade Report at 65.
152 Blade Report at 158.

and outcome at the SS-25 well.

SED further alleges that if a SCADA system were installed, it would have provided insight into the size of the leak. Presumably, by the "size of the leak", SED (and Blade) mean the gas flow rate of the leak. But this is impossible. A SCADA system would have provided no information at all as to the magnitude of the gas leak. A SCADA system measures surface tubing and casing pressures and, if equipped with a well flow meter, the injection or production rate at the wellhead. At the time of the leak, the SS-25 well was injecting gas at a rate of approximately 70 MMscf per day. That is the rate that the SCADA system would have measured, and that rate has absolutely nothing to do with the magnitude of the downhole gas leak. Once the well was shut-in, the gas injection rate would now be zero, but the SCADA system would still not be measuring any flow rate associated with the gas leak because the SCADA system measures data at the wellhead. As the Blade report states, most of the gas from the leak would have "flowed through the heavily weathered and vertically fractured top 200-300 ft. of formation, however, some would have flowed horizontally through permeable or fractured layers away from the SS-25 well site, and some would have remained in the subsurface." It is not possible for a real-time measurement system at the wellhead to detect and measure the gas flow rate outside the wellhead flowing through the geologic strata.

Finally, SED alleges that if a SCADA system were installed, it would have provided insight into the extent of the problem. Once again, this could not be possible. Real-time measurement of surface tubing and casing pressures, as well as gas injection rates, would have yielded no information whatsoever as to the location of the leak in the production casing, the type or size of the rupture in the casing, or as was stated earlier the magnitude of the gas flow rate. SCADA would have yielded no information at all as to the extent of the "problem."

The SED allegations in respect of SCADA are unfounded. SCADA on individual wells was not an industry standard in 2015 in gas storage fields developed in depleted oil and gas fields (80% of the U.S. gas storage fields). SCADA would not have yielded any useful information as to the location or extent of the gas leak in the SS-25 well. And, most importantly, a SCADA system would have made absolutely no difference in the events that transpired at the SS-25 well on October 23, 2015 and thereafter.

IX. SOCALGAS HAD ORGANIZED WELL FILES THAT CONTAINED THE APPROPRIATE AND NECESSARY INFORMATION.

In support of violations 327-329, SED asserts that "SoCalGas did not keep complete, accurate, or accessible records that were necessary for the safe operation and maintenance of its wells at Aliso Canyon Natural Gas Storage Facility." [153]

The SED allegation is incorrect. We note that there are no regulations or documented industry standards prescribing what sorts of documents should go into a well file or how they should be organized. Based on our experience at numerous gas storage fields and with gas storage operators, we believe that the Aliso Canyon well files are in fact well organized and contain the appropriate and necessary information. Each well has four separate files; one for the drilling programs, wellbore schematic, rework history and permits; a second file for downhole logs; a third file for well surveys that includes subsurface pressure data and temperature surveys; and a fourth file for wireline invoices. As noted by SED, they do not include data related to operations or maintenance of related and supporting facilities, which is consistent within the industry. These data would normally be kept in separate files appropriate for that purpose. For example, the Maximo system stores maintenance data related to storage facilities such as wellhead valves, leakage surveys, etc.

[153] SED Opening Testimony at 67.

We have reviewed many of the well files for the Aliso Canyon gas storage field and, based on our experience, it is our opinion that these records were maintained in a manner exceeding the industry standard for U.S. gas storage operating companies.[154] SED's testimony, provided by Ms. Margaret Felts, indicates that she never reviewed the actual physical Aliso Canyon well files.[155] Ms. Felts acknowledges that she only reviewed an electronic production of records from SoCalGas' well files in response to a data request, not a physical well file.[156] Therefore, we believe that without properly reviewing the actual well files, SED cannot appreciate the accuracy or completeness of the SoCalGas well files at Aliso Canyon.

X. CONCLUSION.

This concludes our prepared testimony.

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[154] Notably, SED does not state what it believes industry standards for record organization are. In response to questions about what record *retention* policies it believes were relevant to the industry, SED provided a record retention policy from PG&E. *See* Ex. I-9 (SED Supplemental Data Response to SoCalGas Data Request 3 (as supplemented Jan. 23, 2020)), SED response to question 25(a). However, this PG&E policy, Ex. I-72 ("PG&E.P2-2-Guide.to.Record.Retention-2003"), did not provide any standards or practices for record organization and is therefore irrelevant.

[155] Ex. I-10 at 135:22 – 136:1 (Felts Depo. Tr. 135:22 – 136:1. Further, Ms. Felts testified that she has never looked at recordkeeping practices at other gas storage fields). *Id.* at 312:14-19.

[156] Ex. I-10 at 135:22-136:1 (Felts Depo. Tr. 135:22 – 136:1).

WITNESS QUALIFICATIONS

My name is Timothy L. Hower, P.E. My business address is MHA Petroleum Consultants, 730 17th St., Suite 410, Denver, Colorado 80202.

Credentials and Qualifications

1. I am a Senior Technical Advisor at MHA Petroleum Consultants ("MHA"). I hold an M.S. degree and a B.S. degree in Petroleum Engineering from the Pennsylvania State University. I am a Registered Professional Engineer in the states of Colorado and Wyoming. My qualifications are described in greater detail below and summarized in my curriculum vitae[157]

2. I am a Distinguished Member of the Society of Petroleum Engineers ("SPE"), having been elected so in 2015. Additionally, I have received the C. Drew Stahl Distinguished Alumni Achievement Award from Pennsylvania State University and the Henry Matson Technical Service Award from the SPE for innovative contributions in the field of engineering in gas reservoirs.

3. I have sat on many industry groups including as Chairman of the Denver Section of the SPE from 2001 – 2002, as Chairman of the SPE's Reprint Series on Layered Reservoirs, as Program Chairman of the SPE's Low Permeability Reservoirs Symposium in 1995, 1998, and 2000, and as General Chairman of the 1993 SPE Low Permeability Reservoirs Symposium and the 2005 SPE Rocky Mountain Technical Conference.

4. I have over thirty-six years of petroleum engineering experience, including evaluation and optimization of underground gas storage projects, including Compressed Air Energy Storage (CAES) projects located in the U.S., Europe and Australia. I have conducted industry training courses on reservoir engineering of underground gas storage reservoirs, and co-authored an industry textbook covering gas storage reservoir management.

5. From June 1983 through September 1988, I was the Senior Reservoir Engineer at Tenneco Oil Exploration and Production in Denver, CO. While at Tenneco, I was responsible for managing oil and gas properties in the Rocky Mountain Region. I participated in unitization studies for several enhanced recovery projects in North Dakota and was the lead engineer for Tenneco's interests in the San Juan Basin in New Mexico.

6. From October 1988 through September 1990 I was a Staff Engineer at CNG Development Company in Pittsburgh, PA. I managed oil and gas properties in conventional and unconventional (tight sands, shales, and coalbed) reservoirs. I worked on production forecasting, field optimization, reserve estimation, formulation evaluation, depletion, and drainage studies.

7. From October 1990 through September 1995, I was the Senior Manager of Exploration and Production and a Consulting Engineer for Intera Petroleum in Denver, CO. I provided engineering, simulation and software support for oil and gas clients throughout the

[157] Ex. I-73 (T. Hower CV).

globe and managed a staff of more than 30 geologists, geophysicists, petrophysicists and engineers.

8. From October 1995 through June 1997, I was the Engineering Manager for Enron Oil and Gas Company in Denver, CO and Houston, TX. I was in charge of property evaluations, exploration and exploration drilling programs, secondary recovery design and implementation, reservoir simulation studies, reserve and acquisition evaluations and annual budgeting and forecasting for Enron Oil Company's largest division.

9. From July 1997 through July 2019, I was the President and CEO of MHA Petroleum Consultants. I was responsible for the day-to-day operations of the company with active engineering projects around the world. During this time I worked as a project manager for numerous engineering consulting projects worldwide. In July 2019, I stepped down as President and CEO but remain a senior technical advisor to the company, continuing to consult in projects worldwide and instruct and develop industry-training courses.

10. I have testified as an expert witness in over 100 matters before various state oil and gas regulatory commissions, before numerous district and circuit courts, and before the London High Courts, the London Court of International Arbitration, the High Court of New Zealand and the Supreme Court of South Australia. I have not testified before the California Public Utilities Commission before.

WITNESS QUALIFICATIONS

My name is Charles E. Stinson, PE. My business address is 1892 N Birch St, Canby, OR, 97013.

Credentials and Qualifications

1. I am a Petroleum Engineer at CS Energy Ventures. I hold a B.S. in Applied Mathematics from the University of Colorado. I am a registered Petroleum Engineer in the State of Oregon. My qualification are described in greater detailed below and summarized in my curriculum vitae.[158]

2. I have 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).

3. I have 25 years in management and executive roles with operational and fiscal responsibility for activities including Underground Storage Development & Ops, Natural Gas Marketing, Natural Gas Gathering & Processing, Producing Property Acquisitions, Distribution Facilities Design, Supply Resource Management, Gas & Oil Exploration & Production, Gas Facility Operations & Maintenance, Transmission Pipeline Construction, and Regulatory Compliance.

4. I have held the following senior management positions with multiple technical staff working under my direction. I was Vice President of Engineering & Operations at NW Natural Gas Storage LLC, Vice President of Engineering & Operations at Gill Ranch Storage LLC, Managing Director & Chief Engineer at NW Natural, a local gas distribution company in Oregon, President of Canor Energy Ltd, a Canadian oil & gas exploration company, Vice President & General Manager of Oregon Natural Gas Development Company, and President of Westar Marketing Company, a gas marketing subsidiary of NW Natural.

5. At a 20 Bcf underground gas storage project located in Central California, jointly owned by Gill Ranch Storage LLC and PG&E, I 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.

6. I have managed and directed 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

[158] Ex. I-74 (C. Stinson CV).

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.

7. As Director of Project Development at Mist Gas Storage Field, I had overall management responsibility for the design, permitting and construction of two projects comprising 97 miles of 24" gas transmission pipeline, built to expand the takeaway capacity of the Mist Gas Storage Field described above. 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.

8. Additionally, I have 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.

9. As a member of the Compressed Air Energy Storage (CAES) project team, I headed up the subsurface team in providing expertise and guidance in the selection of suitable reservoirs for testing and potential development. I 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.

10. Additionally, I 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.

11. I am a member of the Society of Petroleum Engineers. Additionally, I was previously the chairman of the Northwest Energy Association (also a director), the American Gas Association Underground Storage Committee, and the Western Energy Institute.

12. I served on the American Gas Association Underground Storage Committee for 20 years, including one year as the 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, I have toured over 30 gas storage fields in 13 states.

13. I have provided expert witness services in two litigations involving underground gas storage facilities, one in California and the other in the Midwest. I have testified in front of the California Public Utilities Commission during the permitting process for Gill Ranch Gas Storage Project.