Long-Term Viability of Underground Natural Gas Storage in California

An Independent Review of Scientific and Technical Information

FULL REPORT

A Commissioned Report prepared by the
California Council on Science and Technology

CCST
CALIFORNIA COUNCIL ON SCIENCE & TECHNOLOGY

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Acronyms and Abbreviations

AAEE	additional achievable electricity efficiency
ACGIH	American Conference of Government Industrial Hygienists
ACS	American Chemical Society
AECO - C	Alberta Energy Company gas trading price
AECOM	Architecture, Engineering, Consulting, Operations, and Maintenance, Inc
AGA	American Gas Association
ALARA	as low as reasonably achievable
ALARP	as low as reasonably practicable
ALJ	administrative law judge
API	American Petroleum Institute
APPA	American Public Power Association
ARB	Air Resources Board
ARFVTP	Alternative and Renewable Fuel and Vehicle Technology Program
ARRPA-E	Advanced Research Projects Agency- Energy
ARW	advanced research WRF
ASOS	automated surface observing system
ASRS	aviation safety reporting system
ATSDR	Agency for Toxic Substances and Disease Registry
AVIRIS-NG	airborne visible/infrared imaging spectrometer
AWOS	automated weather observing system
Bbl	barrel (42 gallons)
bcf	billion cubic feet
Bcfd	billion cubic feet per day
BFW	base of fresh water
BGE	Baltimore Gas and Electric
BOPs	blowout preventers
BPI	bottom of perforation interval
BSEE	Bureau of Safety and Environmental Enforcement
Btu	British thermal unit
c - Si	mono and polycrystalline silicon
C/Q	"concentration over flux" ratio
CAES	compressed air energy storage
CaH2Net	California Hydrogen Highway Network
CAISO	California Independent System Operator
Cal/OSHA	California Occupational Safety and Health Administration
CalEPA	California Environmental Protection Agency
CANDU	Canada Deuterium Uranium
CapEx	capital expenditure
CARB	California Air Resources Board
CASPER	Community Assessment for Public Health Emergency Response
CASRN	Chemical Abstract Service Registry Numbers

CAT	Climate Action Team
CB&I	Chicago Bridge and Iron Company
CCA	community choice aggregation
CCS	carbon capture and sequestration
CCST	California Council on Science and Technology
CDE	California Department of Education
CDSS	California Department of Social Services
CdTe	cadmium telluride
CEC	California Energy Commission
CEMA	California Emergency Management Agency
CEQA	California Environmental Quality Act
CERS	California Environmental Reporting System
cf	Cubic feet
CGR	California Gas Report
CGS	California Geological Survey
CSD	Consumer Services Division
CNG	compressed natural gas
CO2	carbon dioxide
CPC	Climate Prediction Center
CPCN	certificate of public convenience and necessity
CPUC	California Public Utilities Commission
CSFAP	California Sustainable Freight Action Plan
CSP	concentrating solar power
CVGS	Central Valley Gas Storage
DAWG	Demand Analysis Working Group
DE	distributed energy
DG	depleted gas
DGS	Department of General Services
DHR	depleted hydrocarbon reservoir
DHSV	downhole safety valve (see also SSSV)
DIR	(California) Department of Industrial Relations
DO	depleted oil
DOE	Department of Energy
DOG	Department of Oil and Gas
DOGGR	Division of Oil, Gas and Geothermal Resources
DOT	U.S. Department of Transportation
DR	demand response
Dth	10 therms and is equal to 1 MMBtu.
DWH	Deepwater Horizon
DWR	(California) Department of Water Resources
E3	Energy and Environmental Economics, Inc
EAP	Energy Action Plan
EBMUD	East Bay Municipal Utility District
EE	energy efficiency

EFZs	earthquake fault zones
EG	electric generation
EGS	enhanced geothermal systems
EIA	Energy Information Administration
EIS	environmental impact statement
EJ	environmental justice
EOR	enhanced oil recovery
EPIC	California Energy Commission's Electric Program Investment Charge
EPNG	El Paso Natural Gas
ESR	Energy Storage Roadmap
EESI	Environmental and Energy Study Institute
EV	Electric Vehicle
FCEV	Fuel cell electric vehicle
FEMA	Federal Emergency Management Agency
FEP	features, events, and processes
FERC	Federal Energy Regulatory Commission
FSRUs	floating storage regasification units
FT service	firm transportation service
GaAs	gallium arsenide
GHG	greenhouse gas
GRC	general rate case
GS	gas storage
GSI	gridpoint statistical interpolation (analysis system)
GT&S rate	gas transmission and storage
GTN	Gas Transmission Northwest
GW	gigawatt
GWP	global warming potential
GWPC	Groundwater Protection Council
HHE	health hazard evaluation
HOFs	human and organizational factors
HRRR	high-resolution rapid refresh
HSE	Health and Safety Executive (United Kingdom)
HSE	health, safety, and the environment
HSIP	Homeland Security Infrastructure Program
HV	heating value
IARC	International Agency for Research on Cancer
ICE	Intercontinental Exchange
ICRP	International Commission on Radiological Protection (and Measurements)
IDDP	Iceland Deep Drilling Project
IEAGHG	International Energy Agency Greenhouse Gas
IEPR	Integrated Energy Policy Report
IFR	interim final rule
IGCC	integrated gasification combined cycle
ILI	in-line inspection

IME	integrated methane enhancement
INGAA	Interstate Natural Gas Association of America
INPO	Institute of Nuclear Power Operations
IOU	investor owned utilities
ISD	Integrated Surface Database (NOAA)
ISO	International Organization of Standardization
IUR	inhalation unit risk
JPL	Jet Propulsion Laboratory
kg	kilogram
kW	kilowatt
kwh	kilowatt hour
LACDPH	Los Angeles County Department of Public Health
LADWP	Los Angeles Department of Water and Power
LANL	Los Alamos National Laboratory
LBNL	Lawrence Berkeley National Laboratory
LCFS	Low Carbon Fuel Standard
LDC	local distribution company
LES	large eddy simulation
LFL	lower flammability limit
LNG	liquefied natural gas
LOC	loss of containment
LRF	leak rate (required) for flammability
LUAF	lost and unaccounted for
m	meter
M	thousand (e.g., Mcf)
MAE	mean absolute error
MAOP	maximum allowable operating pressure
MATES	Multiple Air Toxics Exposure Study
ME	mean error
MHK	marine and hydrokinetic
MISO	Midwest System Operator
MIT	Mechanical Integrity Testing
MM	thousand thousand = million
MMBtu	million British thermal units
MMcf	million cubic feet
MMcfd	million cubic feet per day
MMscf	million standard cubic feet
MRLs	minimum risk levels
MW	megawatt
MWh	megawatt hours
NAAQS	National Ambient Air Quality Standards
NAESB	North American Energy Standards Board
NARAC	National Atmospheric Release Advisory Center
NASA	National Aeronautics and Space Administration

NCDC	National Climatic Data Center (NOAA)
NCEP	National Center for Environmental Prediction
NCRP	National Council on Radiation Protection
NERC	North American Electric Reliability Corporation
NGV	natural gas vehicles
NHTSA	National Highway Transportation Safety Administration
NIST	National Institute of Standards and Technology
NMOCs	non-methane volatile compounds
NOAA	National Oceanic and Atmospheric Administration
NORMs	naturally occurring radioactive materials
NOx	nitrogen oxides
NREL	National Renewable Energy Laboratory
NTSB	National Transportation Safety Board
NWS	National Weather Service
NYMEX	New York Mercantile Exchange
O&M	operating and maintenance
OEHHA	Office of Environmental Health Hazard Assessment
OFO	operation flow orders
OG	oil and gas
ORA	Office of Ratepayer Advocates
OSHA	Occupational Safety and Health Administration
OSHPD	(California) Office of Statewide Health Planning and Development
OTC	once- through- cooling
P	pressure (MPa, psi, bar)
P2G	power-to-gas
PGT	Pacific Gas Transmission
PAHs	polycyclic aromatic hydrocarbon
PEM	proton exchange membranes
PFDHA	probabilistic fault displacement hazard assessment
PG&E	Pacific Gas and Electric Company
PHES	pumped hydroelectric storage
PHMSA	Pipeline and Hazardous Materials Safety Administration
PIPES	Protecting Our Infrastructure of Pipelines and Enhancing Safety
PM	particulate matter
ppb	part(s) per billion, ppbv = part(s) per billion by volume
ppm	part(s) per million, ppmv = part(s) per million by volume
ppt	part(s) per thousand
PRA	probabilistic risk assessment
PSE	Puget Sound Energy
PSHA	probabilistic seismic hazard analysis
psi	pounds per square inch
Psig	pounds per square inch gauge
PSM	Process Safety Management (Cal/OSHA)
PST	Pacific standard time

PV	photovoltaic
QC	quality control
QRA	quantitative risk assessment
RELs	reference exposure levels
RETI 2.0	Renewable Energy Transmission Initiative 2.0
RfCs	reference concentrations
RFP	request for proposals
RMP	risk management plan
RMR	reliably must-run
RNG	renewable natural gas
RPS	renewable portfolio standards
RUC	rapid update cycle
SCAQMD	South Coast Air Quality Management District
SCCS	Scottish Carbon Capture & Storage
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric
SDWA	Safe Drinking Water Act
SHZs	seismic hazard zones
SLCPs	short- lived climate pollutants
SMR	small modular nuclear reactors
SMS	safety management systems
SMUD	Sacramento Municipal Utilities District
SNG	synthetic natural gas
SNGS	Sacramento Natural Gas Storage
SoCalGas	Southern California Gas Company
SOEC	solid oxide electrolysis cells
SONGS	San Onofre Nuclear Generating Station
SRIA	Standardized Regulatory Impact Assessment
SSEP	storage safety enhancement plan
SSSV	subsurface safety valve (see also DHSV)
SSV	sliding sleeve valve
STEL	short-term exposure limit
SWRCB	State Water Resources Control Board
T	Temperature (°F or °C)
t	tons
TAC	toxic air contaminant
TBM	Tert-Butyl-Mercaptan
TCAP	triennial cost allocation proceeding
tCO2	bicarbonate or total carbon dioxide test
TDS	total dissolved solids
TGN	Transportadora de Gas Natural de Baja California
TLV	threshold limit value
TPHs	total petroleum hydrocarbons
TPP	transmission planning process

TURN	The Utility Reform Network
TWh	net electricity generation
U.S. EIA	United States Energy Information Administration
U.S. EPA	United States Environmental Protection Agency
U.S. NRC	United State Nuclear Regulatory Commission
UGS	underground gas storage
UIC	underground injection control
USDWs	underground sources of drinking water
USGS	United States Geological Survey
VGIR	vehicle- grid integration roadmap
VOCs	volatile organic compounds
WDC	direct current watts
WECC	Western Electricity Coordinating Council
WHO	World Health Organization
WIEB	Western Interstate Energy Board
WMATA	Washington Metropolitan Area Transit Authority
WRF	weather research and forecasting
ZEV	zero emission vehicles

Chapter 1

What risks do California's underground gas storage facilities pose to health, safety, environment, and infrastructure?

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ABSTRACT

1.0 INTRODUCTION

The general purpose of underground gas storage (UGS) is to meet varying demand for natural gas (predominantly methane, CH_4) over daily to seasonal time scales. The California UGS system in 2017 comprises 12 UGS facilities, four in southern California, seven in northern California, and one in central California with a total capacity to store just under 400 Bcf of natural gas. The California UGS reservoirs are all in depleted hydrocarbon reservoirs where natural gas is under high pressure (e.g., >1000 psi (~7 MPa) for most facilities). The handling and containment of high-pressure natural gas, which is highly flammable and explosive, entails risk. Each UGS facility in California is a combination of surface and subsurface systems designed to compress, inject, contain, withdraw, and process natural gas through wells that access the deep pore space of the storage reservoirs. The subsurface part of UGS comprises the reservoir for storage, the caprock (seal) for keeping buoyant gas from flowing upward, the overburden (rock above the caprock or reservoir) which contributes to additional storage security, and the well. We consider the wellhead to be part of the subsurface and surface parts of the UGS system, the latter of which also included flowlines connecting the wells to centralized compression and gas processing facilities. This chapter (Chapter 1) consists of six separate sections that stand alone but are also integrated to describe the risk posed by UGS in California and the mitigation of this risk.

1.1 CHARACTERISTICS OF CALIFORNIA UNDERGROUND GAS STORAGE FACILITIES

We have identified and searched multiple databases and other public sources to gather information to characterize the state of underground gas storage (UGS) in California. Gas injection via gas storage wells occurred in 13 facilities in California in 2015 prior to the Aliso Canyon well blowout (“well blowouts” in California are defined as “the uncontrolled flow of well fluids and/or formation fluids from the well”; Hauser and Guerard, 1993). Gas injection via storage wells ceased in the Montebello facility at the end of 2016 with the approval of the operator’s application to inactivate the injection permit. Three of the four remaining facilities in southern California store gas in depleted oil reservoirs. The remaining facility, along with the one in central and seven in northern California, store natural gas in depleted gas reservoirs. The southern California facilities withdraw original-in-place oil and gas condensates in varying ratios relative to stored gas withdrawn. Various aspects of the facilities utilizing oil reservoirs differ from those utilizing gas reservoirs. For instance, the oil reservoir storage sites have deeper wells installed longer ago, more vertical wells such that wellheads are distributed more widely across the field, and they operate at a lower pressure as a fraction of the initial pressure.

UGS facilities utilizing depleted gas reservoirs are operated by either an investor-owned utility or an independent (non-utility) company. These groups of facilities generally vary from each other, with the independent facilities using wells installed more recently, gas handling plants farther from the storage well field, and longer pipelines, both connecting from the transmission line to the plant and from the plant to the well field. The differences between the three groups of facilities (utility-owned depleted oil reservoirs, utility-owned depleted gas reservoirs, and independently owned depleted gas reservoirs) provide the opportunity to study variations in risk between the groups, and potentially adapt approaches to managing risk utilized in one group of facilities to another group.

A substantial portion of the gas stored in southern California has been via wells installed six to nine decades ago. It does not appear that there is any regulatory limit to the age of a well component utilized for UGS. Temporal failure statistics should be developed for various components and utilized to determine the reasonable life expectancy of, and a time-varying monitoring schedule for, each type of component.

The data utilized to arrive at these characterizations typically do not have quality flags, nor is there a public record of data-quality protocols applied. Outliers exist in the data suggestive of errors, and there are inconsistencies between datasets that indicate errors. A unified database should be developed to avoid these inconsistencies, and a data-quality protocol including data-quality flags should be applied to the database. However, while some of the data inaccuracies may degrade the precision of UGS characterization in this report, the datasets are sufficiently consistent to provide confidence that our characterizations are accurate. We have compactly summarized key characteristics of California UGS facilities in a risk table presented in Section 1.7

1.2 FAILURE MODES, LIKELIHOOD, AND CONSEQUENCES

We review the main failure modes, likelihood of failure, and the consequences of failure of UGS in California. For the purposes of this section, failure is most commonly loss-of-containment (LOC), but it can also be damage to a well or other component that affects health and safety, the environment, or facility operations without LOC. The reason LOC is the main focus is that UGS involves containing through multiple repeated operations (compression, injection, storage, withdrawal, decompression, processing, utilization) of a highly flammable gas at very high pressure. In the subsurface part of UGS, well integrity and reservoir integrity are needed to contain natural gas. Well integrity failures can occur for many reasons, but failure of cement seals and corrosion of casing are two of the main causes of subsurface LOC. Reservoir integrity relies on caprock sealing and lack of transmissive faults, both of which have been known to fail at UGS systems in the past. In the surface part of UGS, failure can occur by damage to pipelines, valves, seals, and many other components relied upon to contain high-pressure gas in the aboveground infrastructure of UGS facilities. Some California UGS facilities identified here are located in regions with particular hazards, among which are seismic, landslide, flood, tsunami, and wildfire hazards, all of which are external events that can affect UGS infrastructure. Human and organizational factors are widely cited as a cause of incidents at industrial facilities such as UGS sites. The likelihood of failure of UGS facilities can be qualitatively estimated by the record of reported incidents in California, which suggests an incident of severity significant enough to have been reported will occur on average 4.1 times per year somewhere in California, and most of these incidents will be due to well integrity failures. But these statistics must be used cautiously, because the overall number of events is relatively small and reporting of incidents has not been regulated or standardized. The consequences of LOC incidents can be catastrophic, as in the case of large releases such as occur during well blowouts or flowline rupture with ignition, or they can occur without impacts to safety but with potential long-term impact to environment, as in the case of chronic low-flow-rate leakage of methane in the context of its role as a greenhouse gas. Dispersion of any emitted gas will occur by air entrainment and surface winds. The dispersion of leaked natural gas and resulting downwind concentrations relevant to ignition and explosivity can be modeled very accurately, provided that local wind and leakage flow rate data are available. Analysis of dispersion of leaked natural gas suggests that the footprint of methane concentrations between the lower and upper flammability limits can be expected to exceed the size of the clustered surface infrastructure (e.g., a compressor pad, gas-processing facility pad, or the clustered wellheads on pads of multiple deviated wells) for large but not impossible leakage fluxes, meaning that the surface infrastructure is vulnerable to explosion hazard. Subsurface leakage of natural gas, e.g., by annular overpressurization, can allow natural gas to flow into underground sources of drinking water (USDW) typically at much shallower levels than the storage reservoir. There are recorded incidents of natural gas leaking to surface that must have encountered USDW, although specifics of the impacts have not been assessed to our knowledge. In general, we believe adherence to the new regulations proposed by California Division of Oil, Gas and Geothermal Resources (DOGGR) will strongly reduce the likelihood of well integrity failures.

1.3 CAPACITY OF UGS SITES: EFFECTS OF AGE AND STORAGE INTEGRITY

The capacity of UGS reservoirs can be affected by the age of the facility through (i) the effects of formation damage and related reservoir processes, (ii) the loss of reservoir integrity through well or caprock seal failure. Any unintended impedance to the flow of fluids into or out of a wellbore (reduction in permeability) is referred to as formation damage (Petrowiki, 2017). Age-related processes affecting depleted oil and natural gas reservoirs include formation damage, grain alteration due to partially fluid-supported sediments, changes in reservoir pressure conditions, and changes in fluid contacts within the pore spaces of the reservoir. Of these, the factor with the greatest potential to affect storage capacity is formation damage, as it affects the productivity of a depleted oil and gas reservoir during gas withdrawal. Operators should carry out proactive approaches to identifying, addressing, and properly mitigating formation damage in advance of the reduction in formation permeability to avoid loss of gas storage reservoir capacity.

The majority of the depleted oil and gas fields converted to UGS in California were originally discovered and developed for oil and natural gas production from 1929 to 1958. Consequently, the majority of the wells used for UGS in California are older wells (see Section 1.1) and these have required extensive well work-overs targeting a variety of integrity-related issues, such as quantity and quality of cement and corrosion of casing.

Well work-overs, themselves, can provide inherent risk and have the potential for accidental releases. The age of these wells and historic well construction practices dramatically increase the likelihood for LOC. Five gas storage fields within the Los Angeles area have experienced gas migration issues due to age of the wells, improperly plugged and abandoned wells that served as avenues for gas migration out of the reservoir, and reliance on repurposed gas storage wells. At the depleted Montebello oilfield in Los Angeles, gas had been injected by SoCalGas at a depth of 7,500 feet since the early 1960s (Bruno, 2014). Gas injection ceased in 1986 after significant gas seeps were discovered at the surface within a large housing development above the gas storage reservoir (Khilyuk et al., 2000). Soil-gas analysis had detected the presence of imported and processed storage gas, several homes were purchased and demolished, and soil-gas extraction system was installed (Miyuzki, 2009).

When old wells are taken out of service due to age or integrity failures, the capacity of a gas storage reservoir is impacted unless new gas storage wells are drilled and completed to retain gas storage capacity and deliverability. Regarding effects on capacity of reservoir integrity in depleted oil and gas field storage operations, the initial confining zone/caprock is relatively secure, as evidenced by hydrocarbon retention (based on the thick cap that acts as a robust seal in preventing migration from the gas storage reservoir), but the seal can sometimes become degraded over time with repeated pressure and stress cycling. The maximum operational reservoir pressure may need to be reduced to manage reservoir integrity problems, thereby impacting capacity. By assessing gas storage reservoir integrity using a holistic approach (i.e., utilizing multiple methodologies such as geophysical logging and pressure testing), the number of incidents associated with loss of storage integrity can be dramatically reduced with the added benefit of maintaining storage capacity.

1.4 Human health hazards, risks, and impacts associated with underground gas storage in California

In Section 1.4, we assess the environmental, public, and occupational health hazards associated with underground gas storage (UGS) in California. We use four primary approaches: (1) an analysis of air toxic emission data reported to regional air districts and to the state; (2) a proximity analysis of populations near UGS facilities and their potential exposure to toxic air pollutants and natural gas fires and explosions using numbers, density, and demographics of people in proximity to UGS facilities and air dispersion modeling; (3) an assessment of air quality and human health impact datasets collected during the 2015 Aliso Canyon incident; and (4) an assessment of occupational health and safety hazards associated with UGS. The approach we take follows the general recommendations of the National Research Council to compile, analyze, and communicate the state of the science on the human health hazards associated with UGS in California.

Human health hazards of underground gas storage include exposures to toxic air pollutants as well as to explosions and fires during normal operations and/or large loss-of-containment (LOC) events. There is also a possibility of subsurface migration of gases and other fluids associated with gas storage into groundwater resources that may be used currently or in the future for drinking water and other uses that can form exposure pathways to people.

Our assessment of the scientific literature, available air pollutant emissions inventory, air pollution and human health monitoring datasets, and population characterization for community and occupational exposures indicate the following:

1. There are a number of human health hazards associated with UGS in California that are predominantly attributable to exposure to toxic air pollutants and gas-fueled fires or explosions during large LOC events. However, many UGS facilities also emit multiple health-damaging air pollutants during routine operations — formaldehyde in particular, which is of concern for the health of workers and nearby communities.

2. Large LOC events (e.g., the 2015 Aliso Canyon incident) can cause health symptoms and impacts in the nearby population and are a key challenge for risk management efforts.

3. UGS facilities located in areas of high population density and in close proximity to populations are more likely to cause larger population morbidity attributable to exposures to substances emitted to the air than facilities in areas of low population density or further away populations.

4. During large LOC events, if emitted gases are ignited, the explosion hazard zone at UGS facilities can extend beyond the geographic extent of the facility, creating flammability hazards to nearby populations.

5. Workers on site are likely exposed to higher concentrations of toxic chemicals during both routine and off-normal operations, and workers on site have greater chance of exposure to fire or explosions during LOC events.

6. There is uncertainty with respect to some of the mechanisms of human health harm related to the 2015 Aliso Canyon incident and other UGS LOC events in the future. This is mostly attributable to the lack of access to data on the composition of stored gas in the facilities and limitations of air quality and environmental monitoring during and after these events. While our research team attempted repeatedly to obtain the relevant gas composition data, we were unsuccessful.

7. California-specific as well as other peer-reviewed studies relevant to California on human health hazards associated with UGS facilities are critically scarce.

Multiple recommendations emerged from our research that could help to reduce the risk of UGS facilities in California, and would greatly benefit the effectiveness of risk managers to protect nearby human populations from the health risks of environmental exposures sourced from UGS facilities. Our recommendations include but are not limited to the following:

1. Require that the composition of gas withdrawn from the storage reservoir over time be disclosed, along with any chemical use on site that could be leaked, intentionally released, or entrained in gas or fluids during LOC events.

2. Require facility-specific meteorological (e.g., wind speed and direction) data-collection equipment be installed at all UGS facilities.[1]

3. Require that improvements to air quality and human health monitoring approaches be implemented both during routine operations and during LOC events.

4. Require that steps be taken to decrease exposure of nearby populations to toxic air pollutants emitted from UGS facilities during routine operations and LOC incidents. These steps could include the increased application and enforcement of emission control technologies to limit air pollutant emissions, the replacement of gas-powered compressors with electric-powered compressors to decrease emissions of formaldehyde, and the implementation of science-based minimum-surface setbacks between UGS facilities and human populations.

5. Require that UGS workplaces conform to requirements of CalOSHA and federal OSHA (Occupational Safety and Health) to protect the health and safety of on-site workers. On-site workers that include but are not limited to employees, temporary workers, independent contractors should fall under these regulations regardless if operators are legally bound to comply.

1.5 ATMOSPHERIC MONITORING FOR QUANTIFICATION OF GHG EMISSIONS AND UGS INTEGRITY ASSESSMENT IN CALIFORNIA

At the time the incident was discovered at Aliso Canyon in fall 2015, there was no reported quantitative operational monitoring program for ambient methane or other trace gases at Aliso Canyon (or any other UGS facility in California). A variety of methane measurement methods was deployed in the months that followed to improve confidence in the SS-25 well leak rate as it evolved in response to efforts to control the well and reduce reservoir pressure by gas withdrawal. These methods include complementary airborne surveys using low-altitude *in situ* sampling and high-altitude remote sensing as follows: (1) total methane emissions were determined using an aircraft equipped with a Picarro *in situ* methane analyzer flying cylindrical patterns around the facility, and (2) spatially resolved emissions from individual infrastructure components were estimated using an aircraft equipped with JPL's Airborne Visible/Infrared Imaging Spectrometer (AVIRIS-NG). Both airborne methods have since been applied to other UGS facilities in California: total facility methane emissions were measured at selected facilities roughly 40 times from June 2014 through

1. The California Air Resources Board (CARB) implemented regulations effective October 1st, 2017 requiring continuous measurement of meteorological conditions at UGS facilities.

August 2017. Local methane emissions were measured roughly 80 times from January 2016 through August 2017 with the AVIRIS-NG method. UGS facilities are also subjected to daily surveys of all wellheads with hand-held gas analyzers, offering the ability to find small concentration anomalies at wellheads. Together, these measurements provide relevant information on current UGS facility emissions, discussed below in the context of greenhouse gas (GHG) emissions as well with regards to integrity implications.

In general, methane (CH_4) emissions from UGS facilities are a potential concern for climate change because methane is a powerful GHG. Methane emissions from the total California natural gas supply chain from production to combustion should be carefully controlled below ~3% of the total amount used if short-term (~20 yr) climate impacts are to be minimized. We compared the recent airborne measurements of methane emissions from gas storage facilities with annual GHG reporting by the UGS operators to the California Air Resources Board. Taken together, the mean emissions of roughly 1,060 kg/hr (~9.3 $GgCH_4$ (~0.5 Bcf annually)) from the active UGS facilities in California are approximately 7.8% of total natural gas-related methane emission estimated by the California Air Resources Board (CARB), and ~2.6 times the CARB estimate for gas storage-related methane emissions. Those emissions are dominated by three facilities: Honor Rancho, Aliso Canyon (after the SS-25 leak repair), and McDonald Island, which contribute 45%, 16%, and 14%, respectively, to the UGS total. We conclude that UGS-related methane emissions appear to be a small part of both California's methane and total GHG emission inventories. However, the ongoing methane emissions from California UGS facilities are roughly equivalent to having a 2015 Aliso Canyon incident every 10 years. This, combined with super-emitter (defined as anomalous relative to expectation) activity at three facilities, suggests a mitigation opportunity for meeting the state's short-lived climate pollutant mitigation targets in the natural gas sector.

Measurements of natural gas emissions at UGS facilities also provide an atmospheric tracer that can enable efforts to monitor the integrity of surface and subsurface infrastructure—potentially offering early warning to minimize the impact of leaks and avoid LOC and other hazardous situations for some failure modes. Methane in particular is both the primary constituent of natural gas and can be measured by a variety of methods to identify, diagnose, and guide responses to integrity issues. Methane emissions are also qualitatively indicative of emissions of toxic compounds (e.g., benzene), though relationships vary across reservoirs. There are many methane measurement methods that can be applied to UGS leak detection; however, they have differing capabilities and limitations. Several of these methods have been successfully demonstrated in operational field conditions at Aliso Canyon, Honor Rancho, and other facilities, including several examples that illustrate the potential for coordinated application of multiple synergistic observing system "tiers."

1.6 RISK MITIGATION AND MANAGEMENT

To address risk mitigation and management of UGS facilities in California, we carried out review and analysis of three related topics: (1) review of key elements that must be included in an effective risk management plan (RMP) for a UGS facility; (2) a discussion of potential additional practices that could improve UGS integrity; and (3) a review and evaluation of regulatory changes under way by DOGGR covering UGS integrity, with comments on the new California Air Resources Board (CARB) methane monitoring regulations for context. We outline the elements of a well-conceived site-specific RMP that must be based on a formal quantitative risk assessment (QRA), and we provide guidance on methodologies to perform rigorous risk assessment. We also provide guidance on a range of other attributes that a RMP must contain. Underlying effective risk management is the idea that there are risk targets or goals, the attainment of which guides risk mitigation activities. Our analysis includes a critique, with recommendations, of the draft DOGGR UGS regulation published May 19, 2017. Some of the specific recommendations relate to the requirements for a site-specific RMP at an UGS site, including the need for each UGS facility to perform a quantitative risk analysis, to perform regular training of the operational staff using written procedures, and to collect failure data and off-normal event data to be compiled in a publicly available database. The current DOGGR draft regulation should explicitly address the importance and role of human and organizational factors as well as safety culture. Another recommendation relates to the need for DOGGR or the industry to develop risk targets or goals to guide decision-making, while still other recommendations relate to specific sections of the draft regulations that require various monitoring and measurement activities to assess and mitigate well integrity issues.

1.0 INTRODUCTION

1.0.1 Overview of Underground Natural Gas Storage in California

The general purpose of underground gas storage (UGS) is to meet varying demand for natural gas (methane, CH_4) over daily to seasonal time scales in the face of constant-rate gas production and limited pipeline transport capacity. In California, UGS is used to meet peak winter direct-use demands (home and business heating), to meet peak summer demands for electricity (e.g., air conditioning), to balance intermittent renewables (wind and solar), and to carry out price arbitrage (see Chapter 2 for complete details on the role of UGS in the California energy system). UGS is carried out in California by connecting underground storage reservoirs to the network of transmission pipelines that deliver natural gas from its sources in gas reservoirs throughout the western U.S., including local California natural gas reservoirs, to its customers in California.

The California UGS system in 2017 comprises 12 UGS facilities, four in southern California, seven in northern California, and one in central California, with a total capacity to store just under 400 Bcf of natural gas. The total amount of gas in the 12 UGS facilities is significantly higher than 400 Bcf because much of the gas in the storage reservoirs is cushion gas, which is essentially gas whose decompression provides the driving force for withdrawal of the last bit of working gas on any withdrawal cycle. The California UGS reservoirs have an average depth of ~5000 ft and are accessed by deep wells. At the depth of the reservoirs, natural gas is under high pressure (e.g., >1000 psi (~7 MPa) for most facilities). The handling and containment of high-pressure natural gas, which is highly flammable and explosive, entails risk. If a large surface loss-of-containment (LOC) incident occurs, fire and/or explosion are possible, with potentially catastrophic consequences for workers, the public, and the UGS infrastructure itself.

1.0.2 UGS Storage Operation Basics

Each UGS facility in California is a combination of surface and subsurface systems (as shown by the schematic in Figure 1.0-1) designed to inject, contain, and withdraw natural gas through wells that access the deep pore space of the storage reservoir. In the surface part of the system, UGS utilizes a pipeline (referred to here as the interconnect) to deliver and receive natural gas to and from the transmission pipeline. The boundary of the UGS facility is taken here as the junction of the interconnect to the transmission pipeline. The interconnect delivers gas to and receives gas from the compressors and gas processing facilities, respectively. These facilities are connected to the wells through what we refer to here as flowlines, which are typically relatively small-diameter pipelines. Note that we consider the wellheads to be both part of the surface infrastructure and part of the subsurface system. The reason for this duality is that wells are subject to hazards at the surface such as impacts by vehicles and landslides and flooding, and yet they are also integral parts of the well, which is primarily part of the subsurface system of containment for UGS. So the wellheads are at the intersection of surface and subsurface systems. Field lines connecting to the wellhead are components of the surface system.

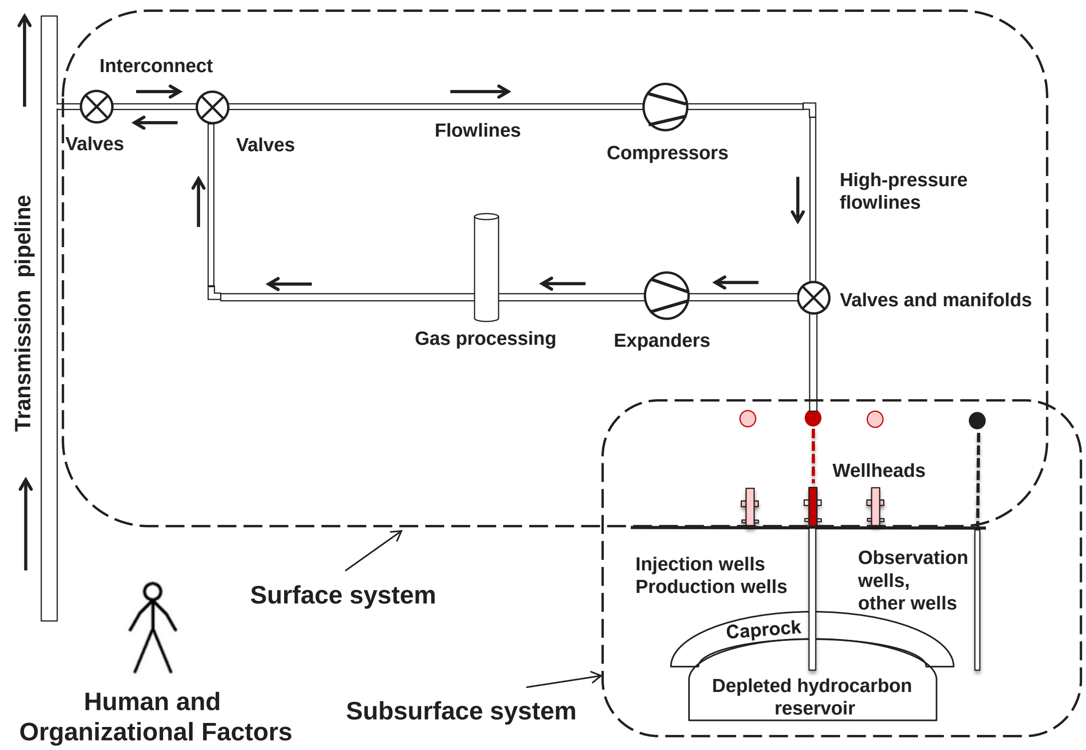


Figure 1.0-1. Simplified schematic of the main components of UGS facilities in California, showing examples of engineered surface components and the wells and geologic features comprising the subsurface system. Human and organizational factors play a critical role in control of both surface and subsurface systems.

Although transmission pipelines are referred to as high-pressure pipelines, gas normally must be compressed in order to be injected through the wells into the storage reservoir (typical pressures greater than 1,000 psi (7 MPa)). Upon withdrawal, gas is normally expanded to lower its pressure and must be processed (e.g., dehydrated) before delivery back to the transmission pipeline. Some processed natural gas may be utilized on-site for powering system components such as turbine compressors.

The subsurface part of UGS comprises the reservoir for storage, the associated deep aquifers that may be present to provide pressure support, the caprock (also referred to as seal) for keeping buoyant gas from flowing upward, the overburden which contributes to additional storage security, and the well and wellhead. Additional wells at UGS facilities may include observation or monitoring wells. Other wells not formally part of the UGS system may also be present, e.g., for oil production from reservoirs not connected to the gas storage reservoir. All wells connected to hydrocarbon reservoirs must be sealed to contain high-pressure gas or oil in the reservoirs. The wells connected to the high gas pressure in the storage reservoir must contain that pressure all the way to the wellhead, after which the surface infrastructure is relied on to contain the gas.

UGS reservoirs in California are all in depleted hydrocarbon reservoirs as described in Section 1.1. Following pressure depletion caused by long-term hydrocarbon production, the hydrocarbon reservoirs can be repressurized by injection of natural gas and repurposed as gas-storage reservoirs. Within the reservoir, natural gas pressure is generally maintained at or below the pressure exerted by water filling the pores of rock prior to the original production of the gas and oil. As such, pressure differentials between gas in the storage reservoir and water in the pores of the rock surrounding the reservoir are not particularly large. Nevertheless, gas does tend to rise in deep formations due to buoyancy. Upward gas migration is resisted by low caprock permeability and by capillary forces that tend to hold water in the small pores of the caprock at the expense of gas. This creates the so-called gas-entry pressure, which is a pressure threshold that must be exceeded in order for gas to displace water from the pores in a rock. Caprock is commonly a fine-grained clay-rich rock that has intrinsically low permeability but more importantly has a high gas-entry pressure, thereby creating a strong barrier to upward gas migration.

The human figure depicted in Figure 1.0-1 represents the human and organizational factors (HOFs) of UGS. Human managers, engineers, and technicians employed by the operating company, along with contractors, provide one component of the human factor element controlling both the surface and subsurface parts of the UGS system. Another part of the human factor component comprises the general public and the local population. In addition, operational practices are inevitably influenced by long- and short-term organizational and cultural factors present in the UGS operating company. Section 1.2.6 and a side bar in Section 1.6 elaborate further on HOF's and safety culture.

1.0.3 Overview of Chapter

In this chapter, we provide a review of the state of UGS in California in the context of the risks entailed by the practice of UGS, and how those risks can be managed and mitigated. Potential consequences arising from UGS failures, such as large-scale LOC from well blowouts, include threats to worker safety and loss-of-life, along with possible public health impacts in downwind populations from natural gas and associated chemical components from the reservoir, including odorants. Large and small flow-rate LOC of natural gas through wells, or leaky valves and seals, may be a concern for its effects on climate because methane is a powerful greenhouse gas, and subsurface leakage of reservoir gases and associated components is a concern for contamination of groundwater. In addition, failure of UGS for any reason can lead to its inability to provide gas to the energy network, a hazard to the stability and reliability of California's energy infrastructure.

This chapter (Chapter 1) consists of six separate sections that stand alone but are also integrated to describe the risk posed by UGS in California and the mitigation of this risk. The benefits and purposes served by UGS in California are covered in Chapter 2. We start in Section 1.1 with a summary of the characteristics of all of the UGS facilities in California. This description sets the stage for Section 1.2, which addresses the ways in which UGS can fail, e.g., resulting in natural gas (mostly methane (CH4)) release, but also potentially releases of other entrained fluids and chemical compounds to the environment, including by well blowout, and the likelihood and consequences of UGS system failures. Section 1.3 addresses the question of loss of capacity of UGS facilities as they age and/or as they suffer storage integrity failures or near-misses of failures. In Section 1.4, we discuss the health and safety hazards related to UGS, including for the general public as well as for workers. In Section 1.5, we present what is known about emissions from UGS facilities of methane in the context of its role as a greenhouse gas (GHG). Finally, in Section 1.6, we discuss risk management, practices to mitigate UGS risks, and the new regulations proposed by the state that are aimed at increasing safety and reliability of UGS in California. The six sections that follow are based on available information and data, the completeness of which varied. As a result, the sections vary in their degree of detail and completeness.

The scientific issues studied within each of the six sections are summarized in a number of findings, conclusions, and recommendations. Findings are facts found by the science team that could be documented or referenced and that have importance to our study. Conclusions are deductions made based on findings (facts). And recommendations are statements that recommend what an entity should do as a result of our findings and conclusions. The most relevant conclusions and recommendations of this chapter were selected by the Steering Committee to be included in the Executive Summary. These selected findings and recommendations are indicated below by their reference number in the Executive Summary. Note that the final conclusions and recommendations included in the Executive Summary were developed in an iterative process based on in-depth discussion within the Steering Committee along with continued consultation with the science team. Final responsibility for these conclusions and recommendations lies with the Steering Committee.

1.0.4 Definitions

Reviewing UGS in the context of hazard and risk entails use of terminology from the fields of oil and gas, gas storage, and risk assessment. In order to make it convenient for the reader to understand terminology in this chapter, we provide up front the following brief table of definitions. Additional terms and acronyms that may not be familiar to all readers are defined in a glossary at the end of the chapter. It is important to note that many of the terms in Table 1.0-1 are defined for use in this report in the context of risk assessment and UGS, and may have more general meanings in common usage.

Table 1.0-1. Definitions of key terms.

Key Terms	Definitions
Accident scenario	Failure scenario, sometimes called an "accident sequence".
Bcf	One billion (109) cubic feet normally referred to as a gas volume. (1 Bcf CH4 = 19,255 tonnes CH4).
Blowdown	Intentional venting of gas from a well or surface component.
Blowout	The uncontrolled flow of gas, liquids, or solids (or a mixture thereof) from a well into the aboveground environment.
Breach blowout	The uncontrolled flow of gas, liquids, or solids (or a mixture thereof) out of fractures or cavities in the ground, the flow of fluid from which originates from well failure.
Capillary trapping	The exclusion of one fluid from entering a rock pore due to the surface tension of its interface with the fluid already in the pore being higher than the pressure difference between the two. Generally, the smaller the pore, the greater the buoyancy of the fluid that cannot enter the pore.
Caprock	The rock overlying the reservoir that prevents buoyant fluids of interest, such as stored gas, from migrating upward out of the reservoir. This can be either via capillary trapping or low permeability (although these typically occur simultaneously because they are both a result of small pore size). Synonymous with seal.
Condition	Measured or observed status, state or property of a system, e.g., the pressure or temperature, the composition of the gas stream, etc.
Consequence	Impact, or quantified negative effect of a failure scenario
Cushion gas	Natural gas in the reservoir that is not withdrawn and that serves to drive out the last bit of working gas on any withdrawal cycle. A.k.a. base gas.
Depleted reservoir	Hydrocarbon reservoir in which the pressure or mass of reserve has been lowered by production to the point that further production of oil or gas is sub-economic.
Dispersion	Dilution and mixing effects associated with transport, e.g., dispersion of CH4 occurs as it is transported by wind.
Event	An occurrence that is relatively short-lived and that affects the safety or operation of a system: e.g., an earthquake, a pipeline rupture, and a breach blowout are all events bearing on UGS safety.
Failure scenario	Sequence of events surrounding a component or system malfunction with resulting negative effects or costs.
Feature	A component or characteristic of a system: e.g., the caprock, wells, and flowlines are some of the features comprising a UGS system.
FEP-scenario approach	Features, Events, and Processes (FEPs), a method to aid in generating a complete and accurate set of failure scenarios.
Hazard	Potential cause of negative effects associated with a component or system failure.
Incident	An event or occurrence affecting a UGS facility involving any or all of the following: Gas release significant enough to warrant reporting, injury/loss of life, damage to property or infrastructure.
Injection	Delivery of fluid (liquid or gas) from the ground surface to the reservoir via wells.
Leakage	Gas or related fluid migration or flow out of the storage system into the environment (subsurface or above ground). Largely synonymous with loss-of-containment.
Likelihood	Probability per year or quantitative or semi-quantitative chance (or expected frequency) of occurrence of the failure scenario
Loss-of-containment (LOC)	Unplanned release to the environment (subsurface or above ground) of gas or related fluid. LOC incidents refer to significant losses of containment of stored gas, i.e., significant enough that it warranted reporting.
Off-normal	Condition characterized by deviation from standard operational or shut-in status, e.g., gas leakage in a system designed to contain gas, plugs in lines that are intended to transport gas, excessively high or low pressure in flowlines, tanks, well tubing or annuli.

Key Terms	Definitions
Plant	In the context of a UGS facility, the plant is the part of the facility with surface infrastructure consisting of any one or all of components such as compressors, gas processing units, electricity generation units, or control room and/or operator office space.
Pool	A reservoir as defined by the California Division of Oil, Gas, and Geothermal Resources. As used in practice by the agency though, a pool may consist geologically of more than one reservoir, such as different sandstone strata within a formation.
Pore	The void space within a rock that can be occupied by a fluid. In a sedimentary rock, this space is that which is not occupied by the original sediments and any material chemically precipitated after deposition of the sediments (cementation).
Process	A long-term or slow change in the system relevant to performance: e.g., corrosion of steel, cement degradation, or sand production are some examples of processes relevant to UGS performance.
Production	Extraction/delivery of fluid (liquid or gas) from the reservoir to the ground surface via a well for the purpose of recovering fluids from a natural accumulation.
Reservoir	A contiguous volume of rock with permeability sufficient to inject and produce or withdraw the fluid of interest at a rate that makes doing so economic.
Risk endpoint	Value to be protected (e.g., health, safety, containment, non-degradation).
Risk	Consequence × Likelihood
Seal	The rock overlying the reservoir that prevents buoyant fluids of interest, such as stored gas, from migrating upward out of the reservoir. This can be either via capillary trapping or low permeability (although these typically occur simultaneously because they are both a result of small pore size). Synonymous with caprock.
Seismic hazard	Likelihood of an earthquake of a given magnitude on a given fault (or within a given area) within a given time.
Spud	To begin drilling a wellbore into the ground.
Subsurface blowout	The uncontrolled flow of gas, liquids, or solids (or a mixture thereof) from a well into the subsurface environment.
Threat	Qualitative potential for a failure scenario to affect something (synonym here for hazard).
Withdrawal	Extraction/delivery of fluid (liquid or gas) from storage in a reservoir to the ground surface via wells.

1.1 CHARACTERISTICS OF CALIFORNIA UNDERGROUND GAS STORAGE FACILITIES

1.1.1 Abstract

We have identified and searched multiple databases and other public sources to gather information to characterize the state of underground gas storage (UGS) in California. Gas injection via gas storage wells occurred in 13 facilities in California in 2015 prior to the Aliso Canyon well blowout ("well blowouts" in California are defined as "the uncontrolled flow of well fluids and/or formation fluids from the well"; Hauser and Guerard, 1993). Gas injection via storage wells ceased in the Montebello facility at the end of 2016 with the approval of the operator's application to inactivate the injection permit. Three of the four remaining facilities in southern California store gas in depleted oil reservoirs. The remaining facility, along with the one in central and seven in northern California, store natural gas in

depleted gas reservoirs. The southern California facilities withdraw original-in-place oil and gas condensates in varying ratios relative to stored gas withdrawn. Various aspects of the facilities utilizing oil reservoirs differ from those utilizing gas reservoirs. For instance, the oil reservoir storage sites have deeper wells installed longer ago, more vertical wells such that wellheads are distributed more widely across the field, and they operate at a lower pressure as a fraction of the initial pressure.

UGS facilities utilizing depleted gas reservoirs are operated by either an investor-owned utility or an independent (non-utility) company. These groups of facilities generally vary from each other, with the independent facilities using wells installed more recently, gas handling plants farther from the storage well field, and longer pipelines, both connecting from the transmission line to the plant and from the plant to the well field. The differences between the three groups of facilities (utility-owned depleted oil reservoirs, utility-owned depleted gas reservoirs, and independently owned depleted gas reservoirs) provide the opportunity to study variations in risk between the groups, and potentially adapt approaches to managing risk utilized in one group of facilities to another group.

A substantial portion of the gas stored in southern California has been via wells installed six to nine decades ago. It does not appear there is any regulatory limit to the age of a well component utilized for UGS. Temporal failure statistics should be developed for various components, and utilized to determine the reasonable life expectancy of, and a time-varying monitoring schedule for, each type of component.

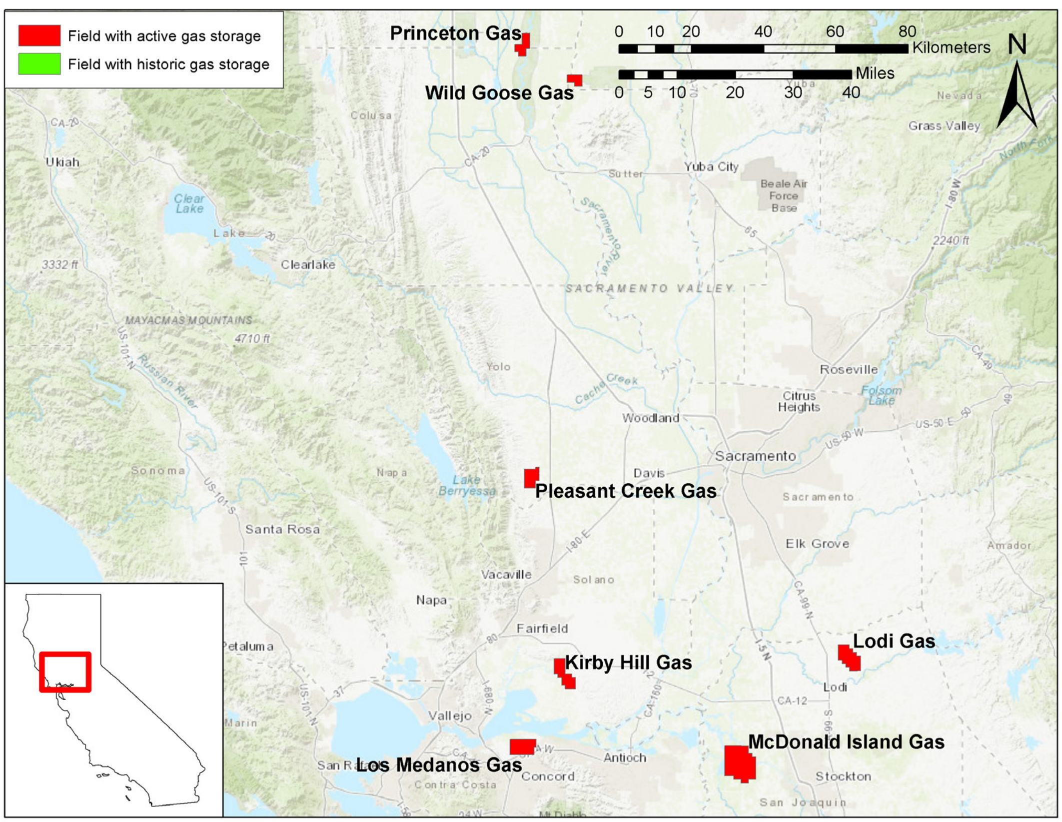
The data utilized to arrive at these characterizations typically do not have quality flags nor is there a public record of data-quality protocols applied. Outliers exist in the data suggestive of errors, and there are inconsistencies between data sets that indicate errors. A unified database should be developed to avoid these inconsistencies, and a data-quality protocol including data-quality flags should be applied to the database. However, while some of the data inaccuracies may degrade the precision of UGS characterization in this report, the datasets are sufficiently consistent to provide confidence that our characterizations are accurate. We have compactly summarized key characteristics of California UGS facilities in a risk table presented in Section 1.7.

1.1.2 Introduction

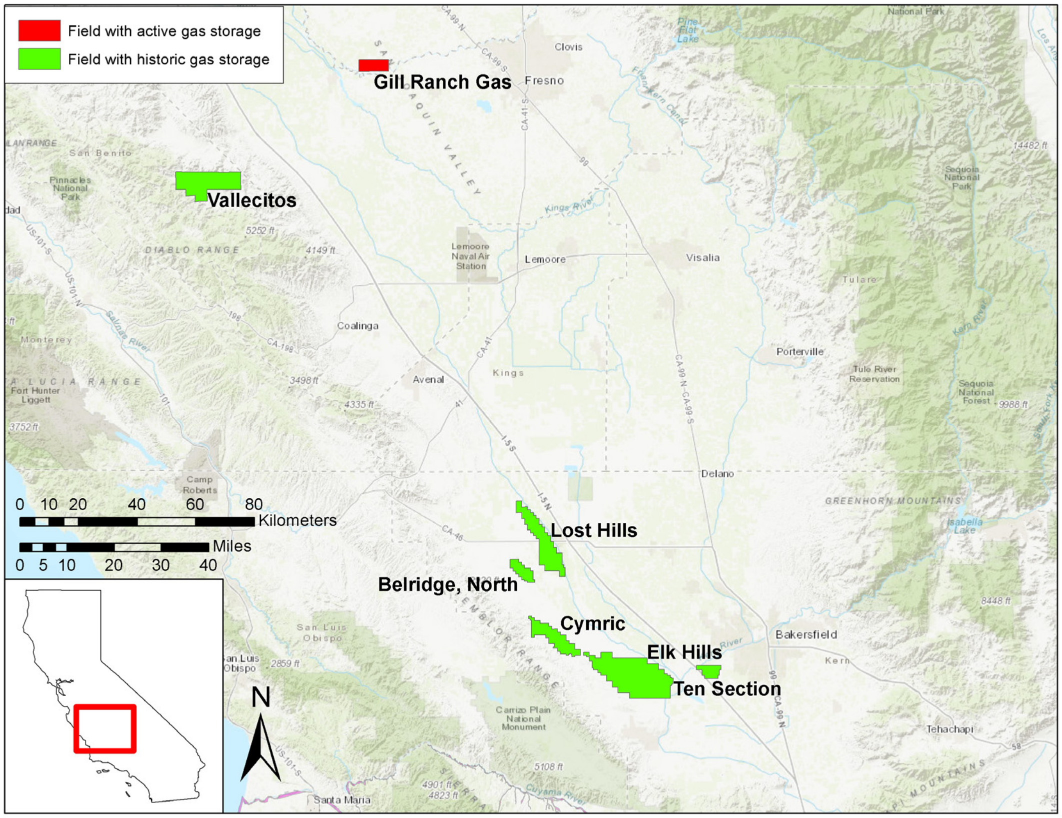
For the purposes of identifying active UGS facilities and characterizing their configuration and operation, we selected January 1, 2006 to December 31, 2015 as the ten-year period for this study. We selected 2015 as the end year to avoid changes from the prior business as usual resulting from the 2015-2016 SS-25 well blowout at the Aliso Canyon facility, referred to here as the 2015 Aliso Canyon incident. For instance, more than a year after the blowout was stopped, injection in a subset of wells previously used for injection at Aliso Canyon recommenced. Consequently, including 2016 and early 2017 in the study period would result in mixing a period of operational stability with a period of operational instability, resulting in a failure to characterize either. An alternative is to characterize each period separately. However, the utility of characterizing the period of operational instability is questionable, because it would not be representative of either the past or the future. For this reason the effort was not expended to characterize this period.

1.1.3 Facilities

The U.S. Energy Information Administration (EIA) maintains data regarding active UGS facilities. We checked the U.S. EIA's list of such facilities in California for consistency against the annual injection databases maintained by California Division of Oil, Gas and Geothermal Resources (DOGGR). We also used those databases to identify facilities no longer in operation. We queried for any well of type GS (gas storage) with gas injection starting from the 1977 database, which is the earliest available, to the 2015 database. From the results of these queries, we generated a list of fields where gas storage occurred during the 2006 to 2015 study period, and had occurred previous to that period. All fields with gas injection via GS wells in that period had such injection in 2015. We term the UGS facilities in these fields "active" and facilities in fields with such injections only prior to 2006 "historic." Figure 1.1-1 shows the location of both types of field.

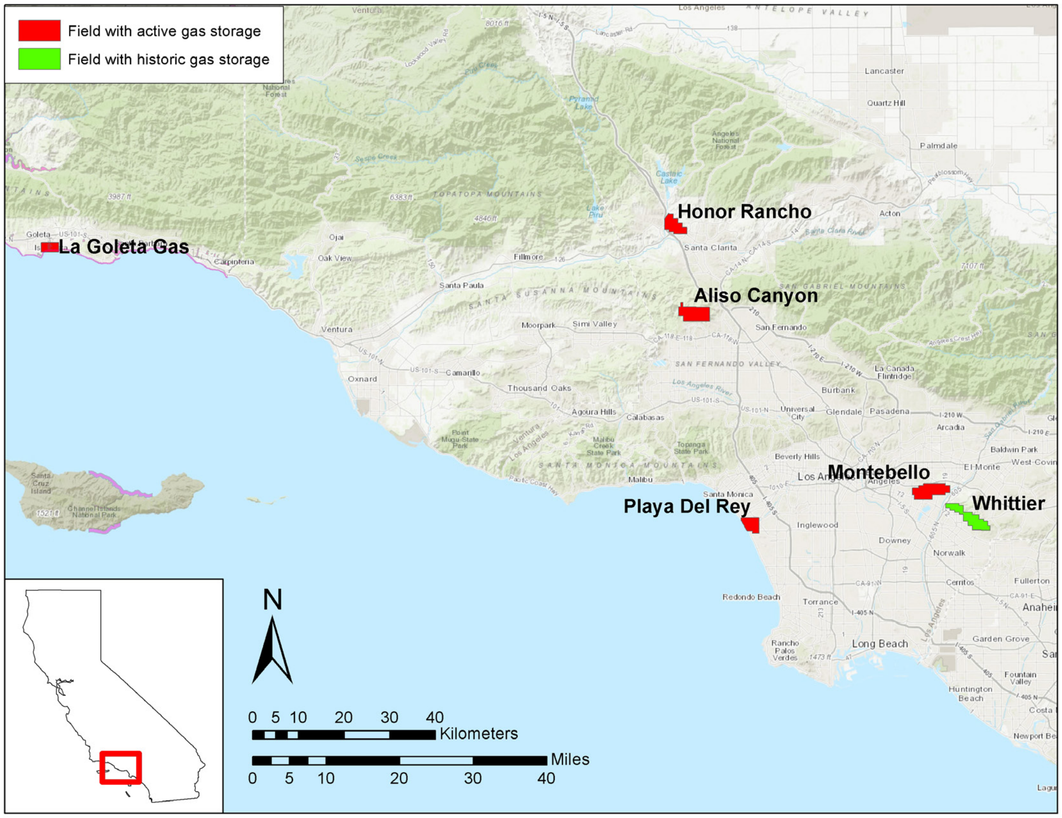


(a)



Field with active gas storage
Field with historic gas storage
Gill Ranch Gas
Vallecitos
Lost Hills
Belridge, North
Cymric
Elk Hills
Ten Section
0 10 20 40 60 80
Kilometers
0 5 10 20 30 40
Miles
N
Clovis
Fresno
Lemoore
Visalia
Coalinga
Avenal
Kings
Porterville
Delano
Bakersfield
Kern
Tehachapi
Santa Maria

(b)



(c)

Figure 1.1-1. Fields with historic or active gas storage as of 2015: (a) northern California, (b) central California, and (c) southern California.

The query results confirmed that each UGS facility on the list available from the U.S. EIA was active, and the query identified one additional field (Montebello) with active gas storage; injection via GS wells in this field occurred every year from commencement of storage operations through 1992. It recommenced in 2011 and continued through the 2015 end of the study period. We also queried the 2016 injection database and found injection in this field via GS wells occurred that year as well.

Given the discrepancy with the list from the U.S. EIA regarding storage in the Montebello field, we inquired with DOGGR about the status of this storage operation. In response, DOGGR provided a letter stating the gas storage project in this field was terminated on December 31, 2016 (DOGGR, 2016). Because this facility was active at the end of the study period and beyond, it is included through Section 1.1.3, which discusses the reservoirs (pools) within which gas is stored in each facility. It is not considered beyond this because the amount of gas transferred through the facility was an order of magnitude smaller than the facility with the next smallest gas transferred during the study period. The continued low-level operation and final closure of the Montebello facility at the end of 2016 accounts for the apparent discrepancy in this report as to the number (13 or 12) of UGS facilities in California.

All of the fields with gas storage had either oil or gas production prior to the commencement of storage, i.e., UGS in California is all in depleted hydrocarbon reservoirs (DHRs). While active storage occurs in more than one reservoir in some fields, prior production from all pools with storage in each field was either of gas or oil. The primary resource type produced in each field is listed in Table 1.1-1. The independently operated facilities are those other than the facilities operated by PG&E and SoCalGas, which are both regulated utilities.

Table 1.1-1. Characteristics of UGS facilities with gas injection via wells designated GS (gas storage) by DOGGR in California in 2015.

Field[1]	Capacity (Bcf)[2]		Start year[4]	Storage Pool Type	Colocated active production	County	Owner
	2006	2015					
Aliso Canyon	82.0	86.2	1973	Oil	Oil	Los Angeles	SoCalGas
Gill Ranch Gas	0.0	20.0	20105	Gas	Gas	Madera	Gill Ranch LLC (75%), PG&E (25%)
Honor Rancho	23.0	27.0	1975	Oil	None	Los Angeles	SoCalGas
Kirby Hill Gas	5.0	15.0	19756	Gas	Gas	Solano	Rockpoint
La Goleta Gas	21.5	19.7	19427	Gas	Gas	Santa Barbara	SoCalGas
Lodi Gas	17.0	17.0	2001	Gas	None	San Joaquin	Rockpoint
Los Medanos Gas	17.4	17.9	1976	Gas	Gas	Contra Costa	PG&E
McDonald Island Gas	82.0	82.0	1962	Gas	Gas	San Joaquin	PG&E
Montebello	Unlisted		1956	Oil	Oil	Los Angeles	SoCalGas
Playa del Rey	2.6	2.4	19428	Oil	None	Los Angeles	SoCalGas
Pleasant Creek Gas	2.3	2.3	1962	Gas	Gas7	Yolo	PG&E
Princeton Gas3	0.0	11.0	20125	Gas	None	Colusa	AGL (through Pivotal Energy Development)
Wild Goose Gas	20.5	75.0	1998	Gas	None	Butte	Rockpoint
Total - independents	42.5	138.0					
Total - PG&E	101.7	102.2					
Total - N.	144.2	240.2					
Total - S. (SoCalGas)	129.1	135.3					
Total	273.3	375.5					

1 As per DOGGR's production and injection databases

2 U.S. EIA (2016)

3 Operated under the name "Central Valley"

4 Except as noted, from earliest injection noted is for storage in DOGGR's annual reports (available at http://www.conservation.ca.gov/dog/pubs_stats/annual_reports/Pages/annual_reports.aspx)

5 Annual reports after 2009 do not note storage; beginning of storage in this period based on first injection year in DOGGR's injection database.

6 Storage activities in the Domengine pool have ceased for several multi year periods since first commencing in 1975; storage in the Wagenet pool commenced in 2008.

7 Earlier annual reports do not list any storage, but this start year is also implied by the statement "the field will probably be utilized as a gas storage reservoir by Pacific Lighting Corporation" in annual report Volume 26 (1940-41).

8 The annual report for 1942 (DOG, 1942) lists injection in the second half of 1942, but does not note it was for storage, however storage in this field is noted in the 1943 annual report (DOG, 1943). Start of storage taken as 1942 based on injection that year.

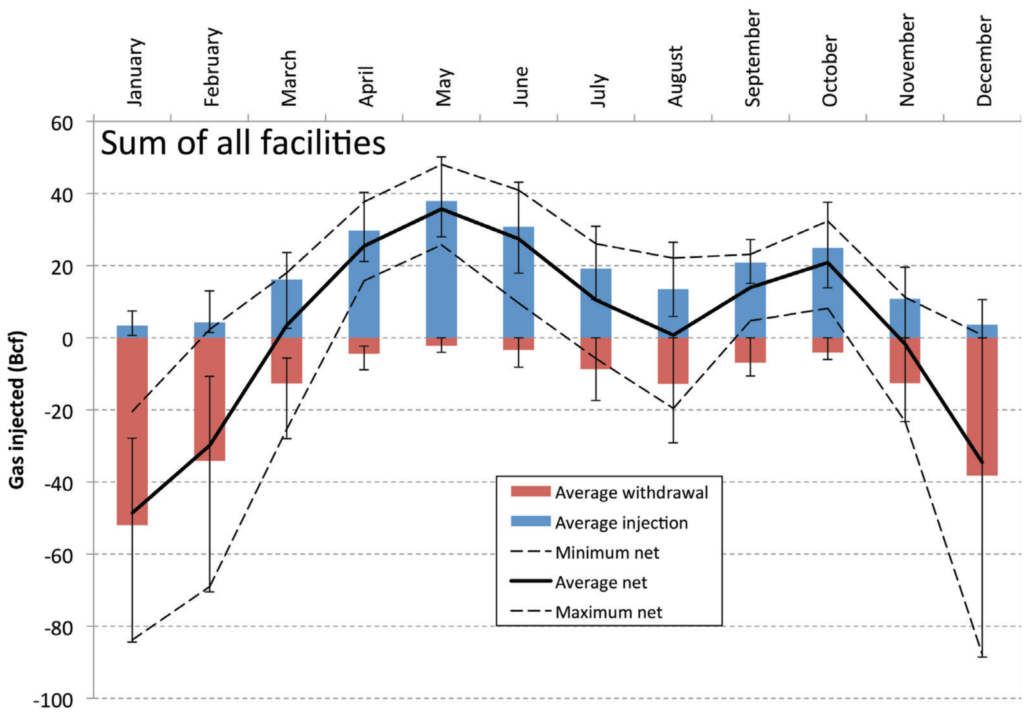
All the facilities in central and northern California were developed in former gas fields, as was the facility in the La Goleta Gas field in southern California. About half of the facilities are in fields with ongoing oil or gas production from other reservoirs.

As shown on Table 1.1-1, storage capacity increased by almost 40% during the 2006 to 2015 study period. This occurred because of a combination of new facilities, such as the Gill Ranch Gas field commencing operation, and existing facilities, such as the Wild Goose Gas field expanding. The independent operators constructed almost the entirety of the additional capacity, and did so in the Central Valley rather than in the Los Angeles area.

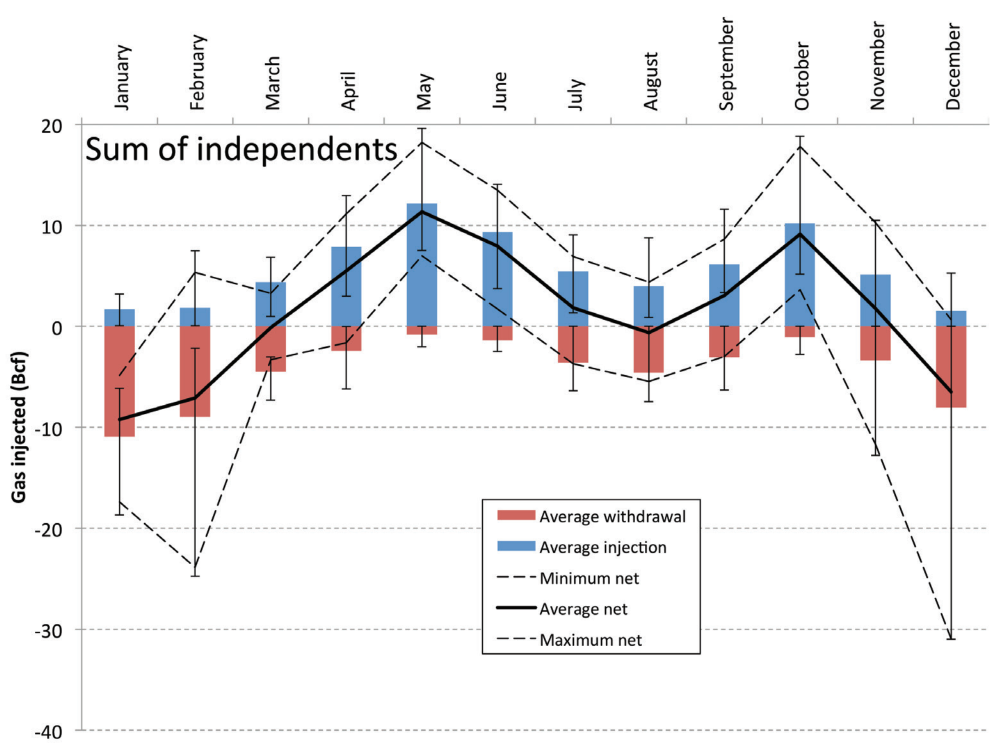
1.1.4 Operation

Temporal patterns of injection to and withdrawal from storage are the result of operations to serve many purposes, as discussed in Chapter 2 and listed in Figure 13 of that chapter. These patterns are characterized in this section, and only their relation to heating and cooling demand is explored.

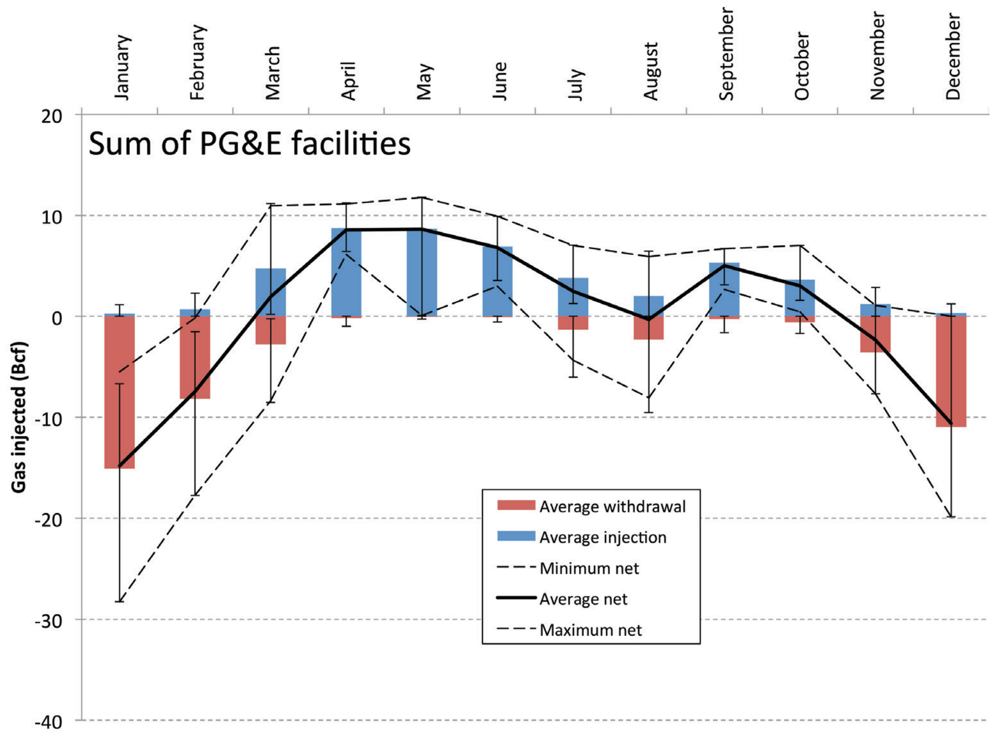
Statewide, withdrawal from storage occurred in two peaks annually on average during the 2006 to 2015 study period, as shown on Figure 1.1-2, with the larger peak centered in January and the smaller centered in August. Injection to storage also occurred in two peaks, centered in May and October. The winter peak occurred in every study year, while the summer peak only occurred in some years. Injection almost ceased during the winter withdrawal peak, but continued through the summer withdrawal peak. As a consequence, withdrawal in August was almost equal to injection on average.


January
February
March
April
May
June
July
August
September
October
November
December
Sum of all facilities
Gas injected (Bcf)
60
40
20
0
-20
-40
-60
-80
-100
Average withdrawal
Average injection
Minimum net
Average net
Maximum net

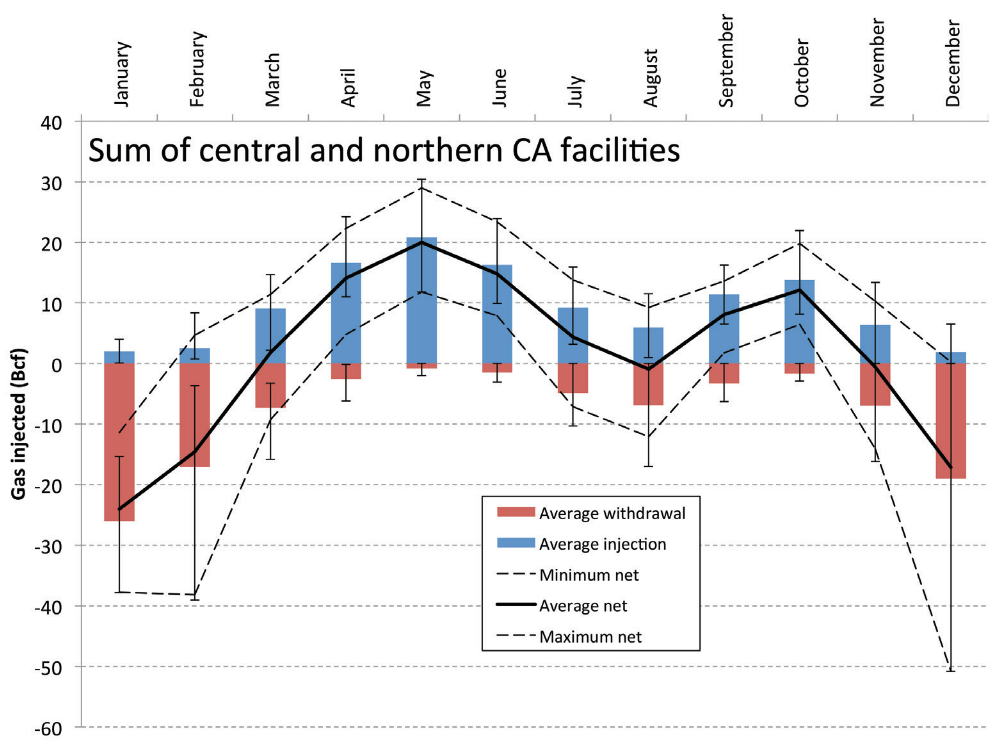
(a)


January
February
March
April
May
June
July
August
September
October
November
December
Sum of independents
Gas injected (Bcf)
20
10
0
-10
-20
-30
-40
Average withdrawal
Average injection
Minimum net
Average net
Maximum net

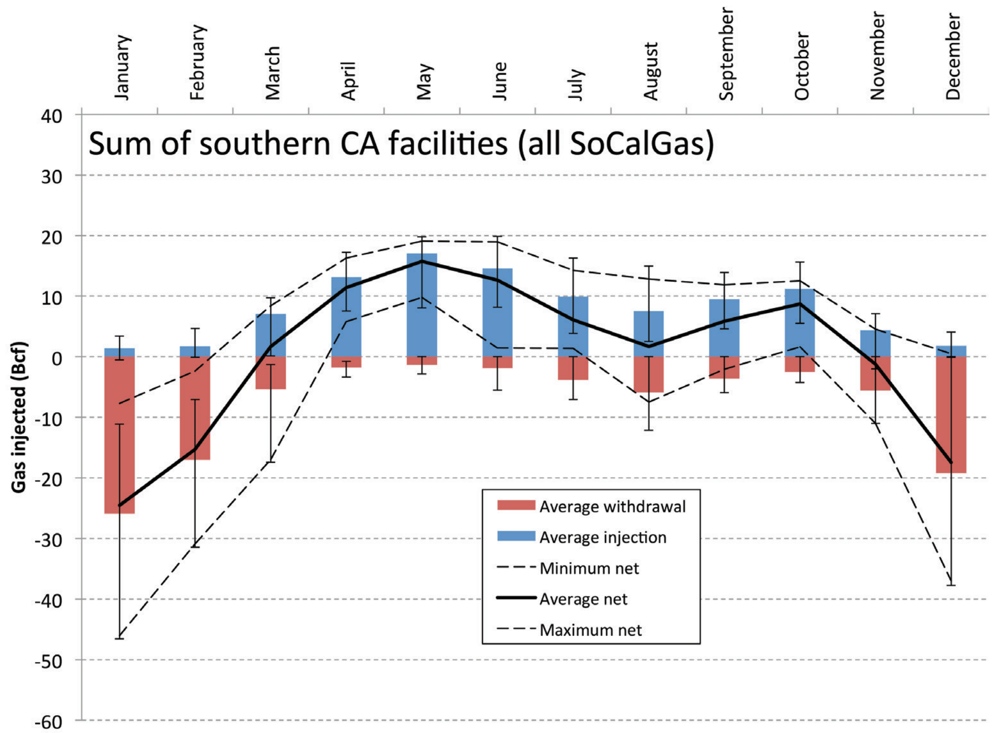
(b)


Sum of PG&E facilities
January
February
March
April
May
June
July
August
September
October
November
December
Gas injected (Bcf)
20
10
0
-10
-20
-30
-40
Average withdrawal
Average injection
Minimum net
Average net
Maximum net

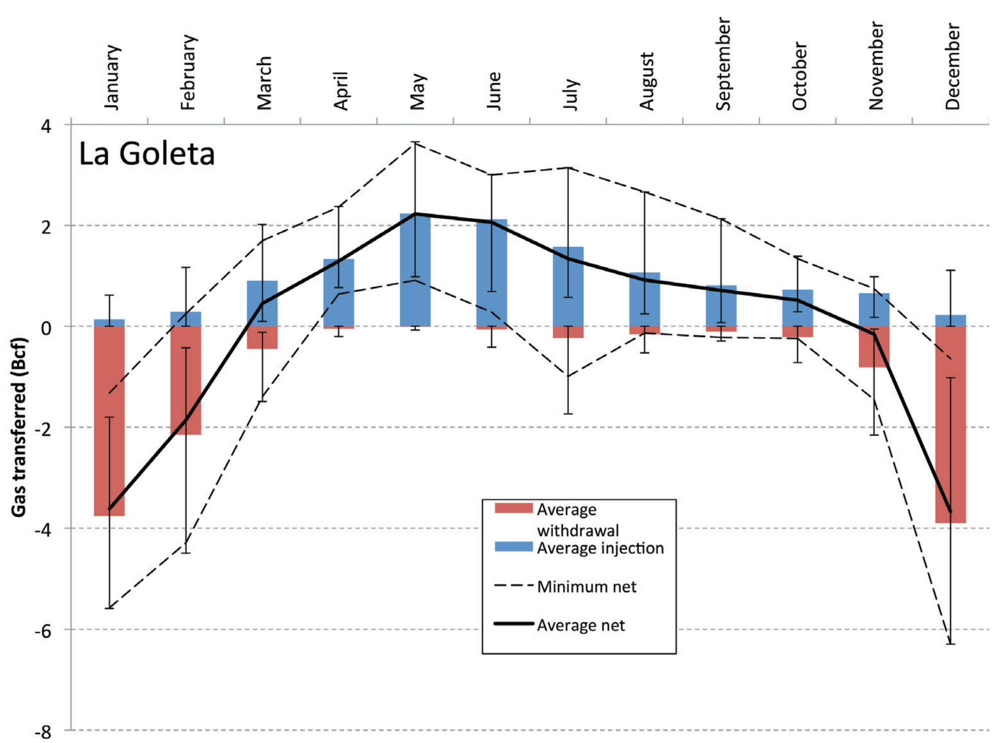
(c)


Sum of central and northern CA facilities
January
February
March
April
May
June
July
August
September
October
November
December
Gas injected (Bcf)
40
30
20
10
0
-10
-20
-30
-40
-50
-60
Average withdrawal
Average injection
Minimum net
Average net
Maximum net

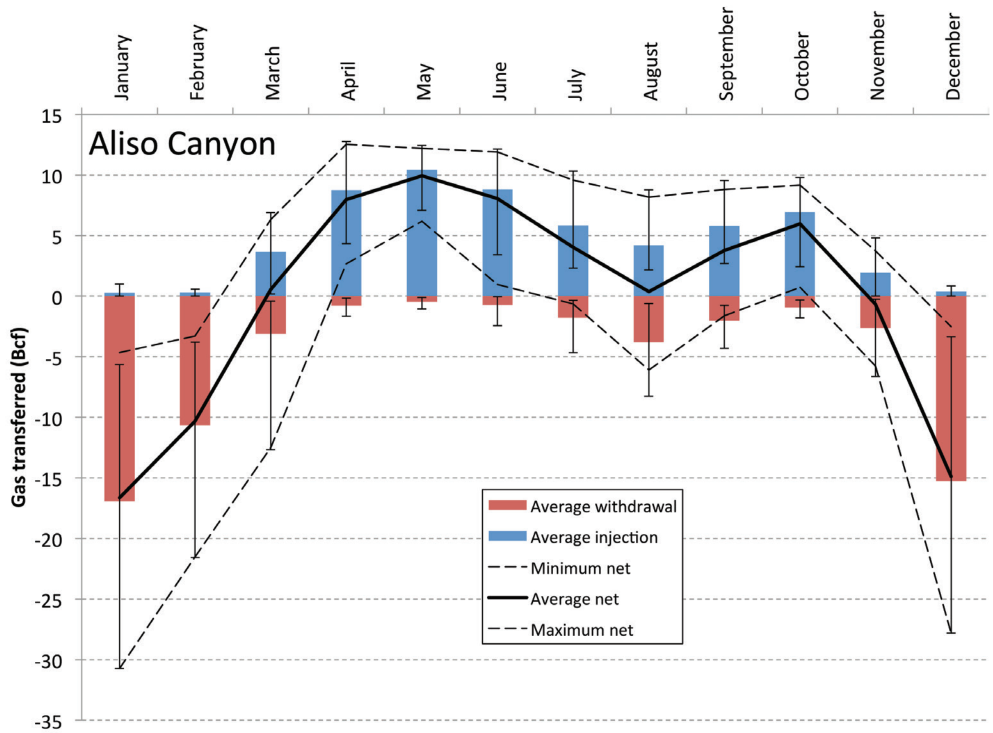
(d)


January
February
March
April
May
June
July
August
September
October
November
December
Sum of southern CA facilities (all SoCalGas)
Gas injected (Bcf)
40
30
20
10
0
-10
-20
-30
-40
-50
-60
Average withdrawal
Average injection
Minimum net
Average net
Maximum net

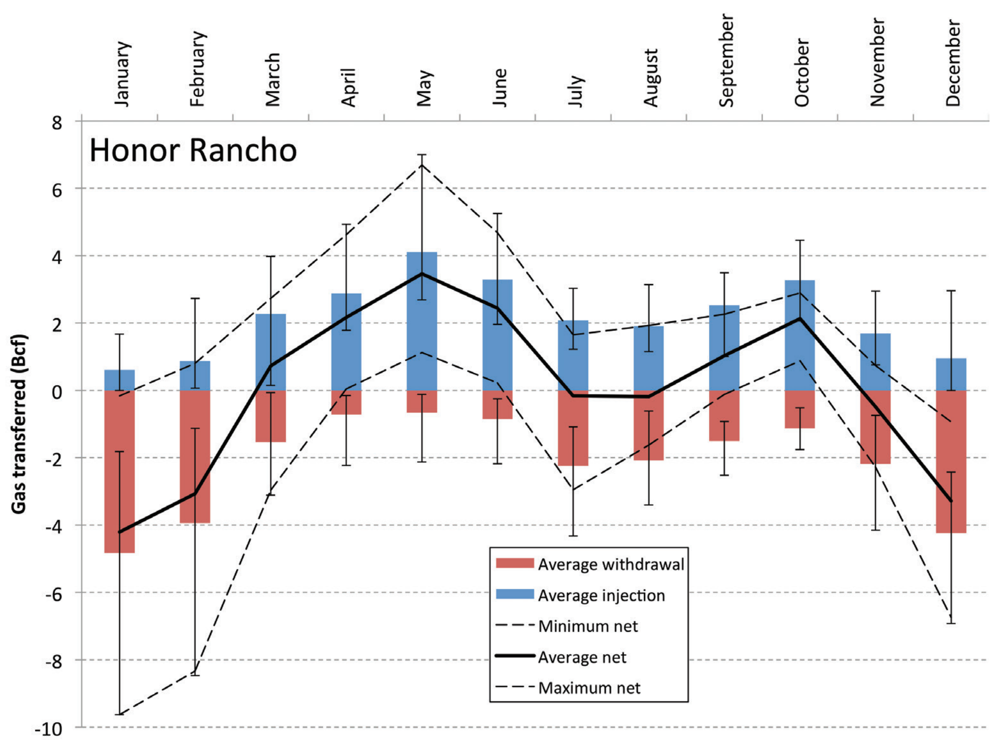
(e)


January
February
March
April
May
June
July
August
September
October
November
December
La Goleta
Gas transferred (Bcf)
4
2
0
-2
-4
-6
-8
Average withdrawal
Average injection
Minimum net
Average net

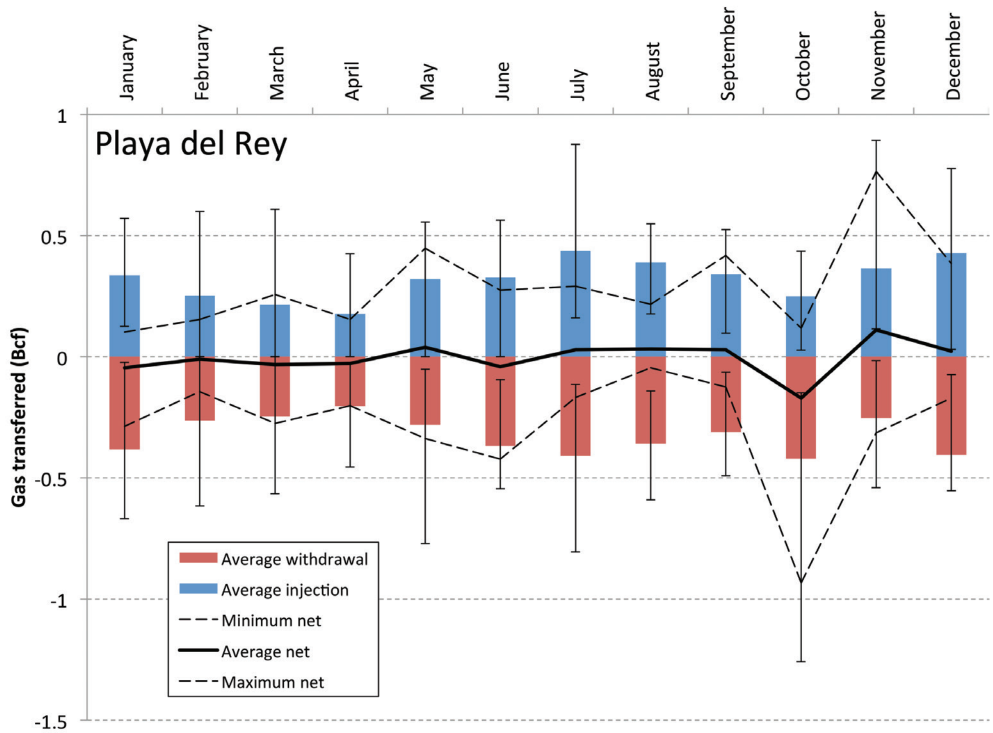
(f)


Aliso Canyon
January
February
March
April
May
June
July
August
September
October
November
December
Gas transferred (Bcf)
15
10
5
0
-5
-10
-15
-20
-25
-30
-35
Average withdrawal
Average injection
Minimum net
Average net
Maximum net

(g)


Honor Rancho
January
February
March
April
May
June
July
August
September
October
November
December
Gas transferred (Bcf)
8
6
4
2
0
-2
-4
-6
-8
-10
Average withdrawal
Average injection
Minimum net
Average net
Maximum net

(h)



(i)

Figure 1.1-2. Monthly injection to and withdrawal from UGS facilities in California from 2006 to 2015 based on DOGGR's production and injection database: a) sum of all facilities, (b) sum of independently operated facilities, which are all in central and northern California (Gill Ranch Gas included because it is part owned by PG&E), (c) PG&E-operated facilities, (d) sum of northern California facilities, (e) sum of southern California facilities, which are all operated by SoCalGas, (f) La Goleta, which has the lowest ratio of summer to winter withdrawal, (g) Aliso Canyon, which is an example of a low summer to winter withdrawal ratio, (h) Honor Rancho, which is an example of a high intermediate summer to winter withdrawal ratio, and (i) Playa del Rey, which has the highest ratio of summer to winter withdrawal. Summer is the sum of withdrawal in July, August, and September. Winter is the sum of withdrawal in December, January, and February. The whiskers extend to the minimum and maximum values in the study period.

This annual pattern of withdrawal and injection was remarkably similar in northern and southern California, as shown on Figure 1.1-2 and quantified in Table 1.1-2. The main difference is the injection peaks are slightly higher and troughs between peaks slightly lower in northern California.

Facilities operated by both PG&E, which is regulated by the CPUC, and independent companies not regulated by the CPUC exist in northern California. PG&E's facilities withdrew slightly more gas in the winter peak on average; however, withdrawal from the independents varied more between years than did withdrawal from PG&E's facilities. The independent facilities withdrew three times as much gas as the PG&E facilities during the summer peak on average; however, withdrawal from PG&E facilities varies more between years than did withdrawal from the independent facilities.

The annual pattern of withdrawal and injection varied between facilities. Figure 1.1-2 shows each of the extremes and examples of intermediate patterns. The annual pattern ranges from almost no summer withdrawal to relatively uniform monthly withdrawal and injection throughout the year. Table 1.1-2 has the ratio of withdrawal to injection in the peak winter and summer withdrawal months of January and August, respectively. Although data more frequent than monthly are not publicly available, the closer to unity (one) the withdrawal to injection ratio is for a month, the more times wells are likely switched from injection to withdrawal and back in the facility, or from non-operation to withdrawal in the case of some wells as discussed below.

Table 1.1-2. Operational statistics from 2006 to 2015 for each UGS facility in California active as of 2015.

Field	Average withdrawal					Average withdrawal / injection	
	Winter[2] (Bcf)	Summer3 (Bcf)	Summer /winter	Of capacity annually	SD[4] of capacity annually	January	August
Gill Ranch Gas	4.1	1.3	0.32	0.35	0.62	51	7.9
Kirby Hill Gas	5.9	2.5	0.42	1.08	1.25	32	1.8
Lodi Gas	7.4	6.2	0.84	0.70	1.29	3.0	2.4
Princeton Gas[1]	3.0	1.1	0.37	0.56	0.77	4.9	2.2
Wild Goose Gas	11.5	1.6	0.14	1.28	1.59	7.8	0.24
Independents	28	11	0.39	0.72	1.08	6.4	1.2
Los Medanos Gas	7.6	1.0	0.13	0.57	0.77	infinite	2.2
McDonald Island Gas	26	2.5	0.10	0.45	0.61	39	0.8
Pleasant Creek Gas	0.80	0.32	0.40	0.55	1.11	62	5.2
PG&E	34	3.9	0.11	0.47	0.58	57	1.2
PG&E and independents (northern CA)	62	15	0.24	0.56	0.68	13	1.2
Aliso Canyon	40	6.9	0.17	0.69	0.84	20	0.82
Honor Rancho	12.0	5.1	0.43	0.35	0.62	7.8	1.0
La Goleta Gas	8.9	0.3	0.03	1.08	1.25	27	0.14
Montebello	0.037	0.032	0.86	NA		1.6	1.4
Playa del Rey	0.97	0.96	0.99	1.59	1.95	1.1	0.83
SoCalGas (southern CA)	62	13	0.21	0.76	0.89	19	0.78
Total	120	28	0.23	0.64	0.77	16	0.95

1 Operated under the name "Central Valley"

2 Sum of withdrawal in December, January, and February

3 Sum of withdrawal in July, August, and September

4 Standard deviation

Table 1.1-2 also lists the average withdrawal relative to capacity for each facility during the study period, as well as the standard deviation of this value. Figure 1.1-3 shows these data plotted against average capacity of each facility from 2006 to 2015. No pattern is apparent other than that some of the smaller facilities have substantially higher capacity utilization.

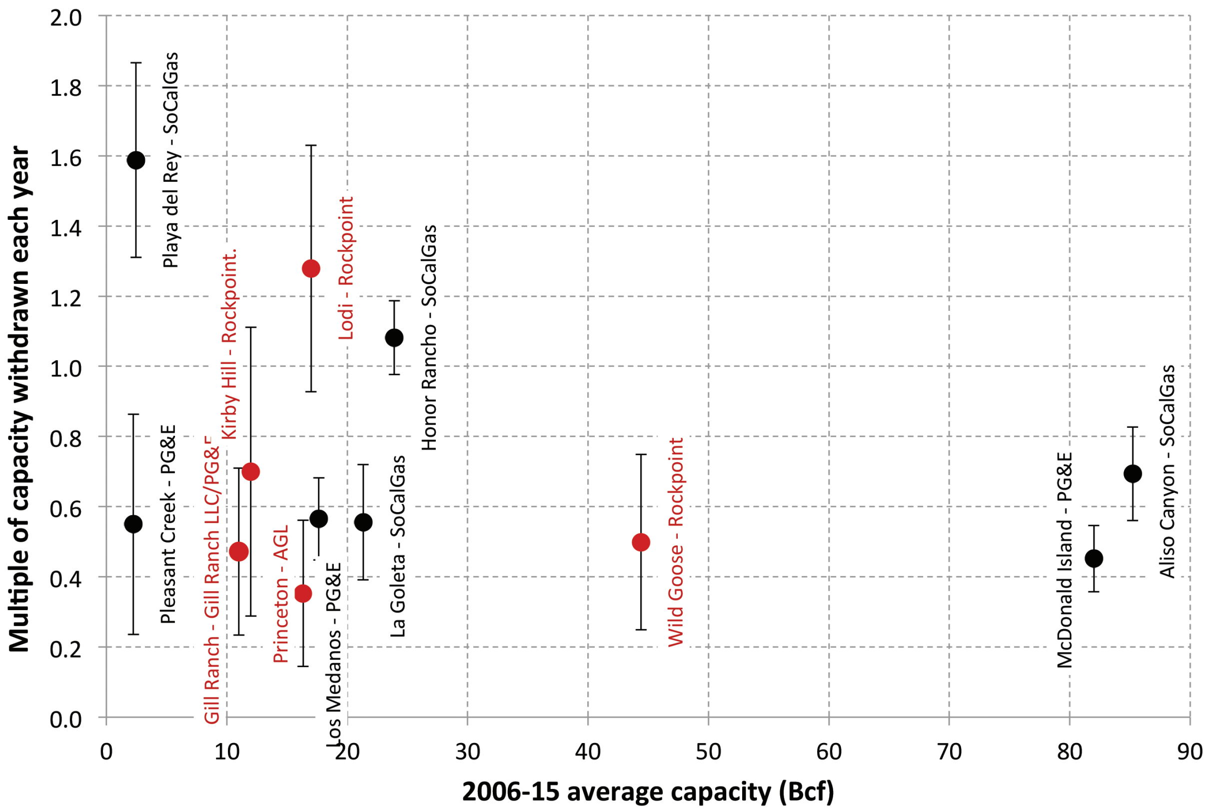


Figure 1.1-3. Annual withdrawal from each facility as a fraction of capacity plotted against average facility capacity from 2006 to 2015. Data for facilities operated by independent companies are plotted in red and for the investor-owned utilities in black.

Statewide withdrawal from storage correlates to total heating and cooling demand on a monthly basis, as shown in Figure 1.1-4. The majority of the variation in withdrawal from storage is correlated to the variation in total monthly heating and cooling demand. The remainder of the variation is likely correlated to some of the other purposes for which storage is operated, as explained in Chapter 2, Figure 13.

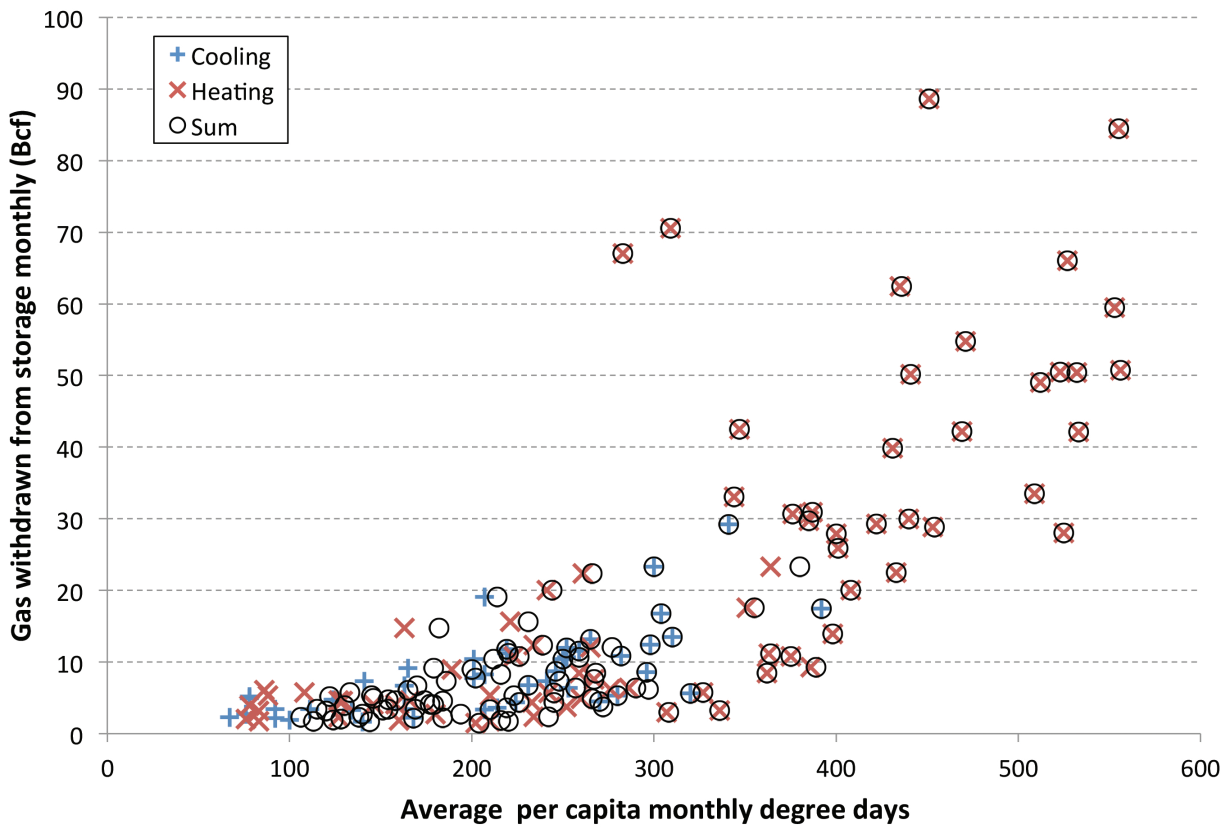
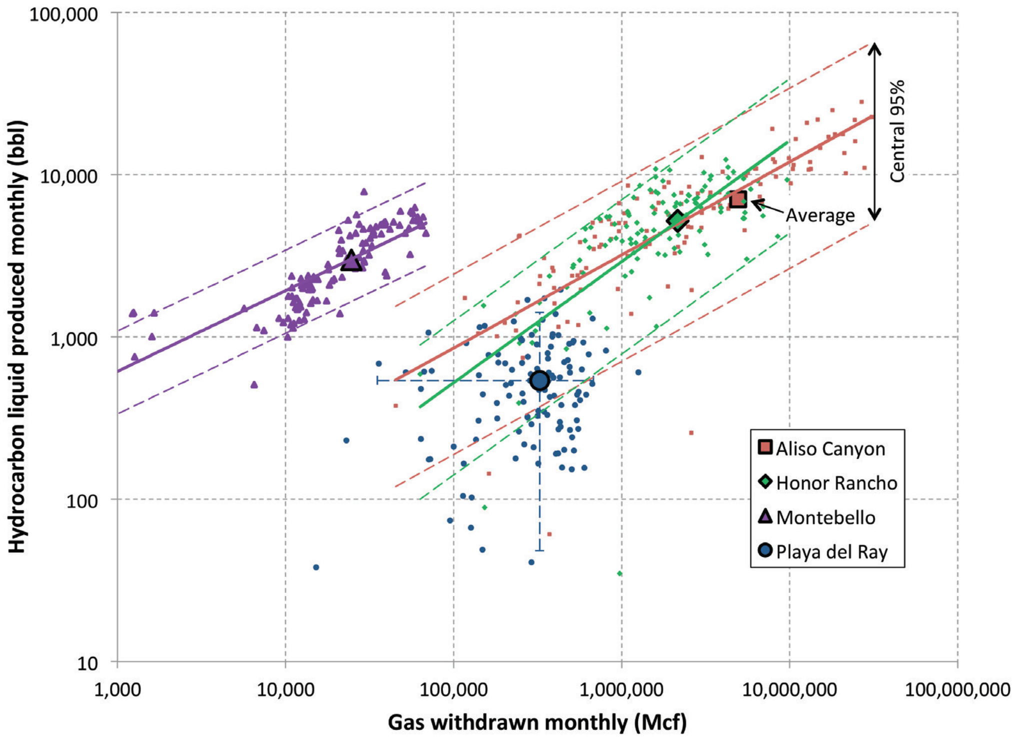
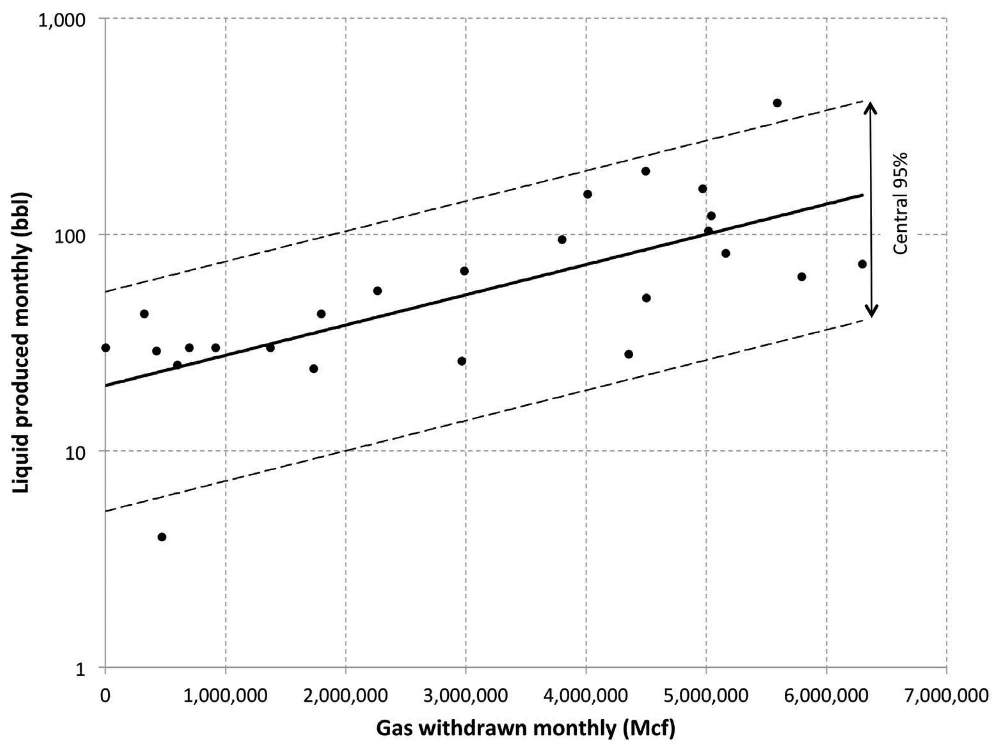


Figure 1.1-4. Monthly gas withdrawal from storage versus average per capita heating and cooling-degree days in California in 2006 to 2015. Degree days are a measure of heating and cooling demand. Degree heating days for a given day is the base temperature less the average temperature for that day, or zero if the average temperature is greater than the base temperature. Degree cooling days are the converse. Average per capita degree days by state were downloaded from the Climate Prediction Center (CPC) at ftp://ftp.cpc.ncep.noaa.gov/htdocs/degree_days/weighted/daily_data/. The base temperature used by the CPC in calculating these data was 65° F.

As shown in Table 1.1-1, four of the UGS facilities were developed in oil fields. Production of oil along with stored gas withdrawn is reported in each of these facilities in DOGGR's production databases during the study period. The relationship between stored gas withdrawal and oil production is shown in Figure 1.1-5a. In addition, production of oil and condensate production along with stored gas withdrawal is reported at the La Goleta Gas facility. No condensate is produced from storage at La Goleta Gas in three quarters of the months with stored gas withdrawal. The relationship between stored gas and condensate withdrawal during the other months is shown in Figure 1.1-5b.


100,000
10,000
1,000
100
10
Hydrocarbon liquid produced monthly (bbl)
1,000
10,000
100,000
1,000,000
10,000,000
100,000,000
Gas withdrawn monthly (Mcf)
Central 95%
Average
Aliso Canyon
Honor Rancho
Montebello
Playa del Ray

(a)


1,000
100
10
1
Liquid produced monthly (bbl)
0
1,000,000
2,000,000
3,000,000
4,000,000
5,000,000
6,000,000
7,000,000
Gas withdrawn monthly (Mcf)
Central 95%

(b)

Figure 1.1-5. Monthly oil and gas condensate production versus stored gas withdrawal at (a) UGS facilities developed in oil fields, and (b) La Goleta Gas UGS facility. Oil and gas condensate are reported together in DOGGR's production data as both are liquids at surface pressures and temperatures and consequently difficult to report separately.

1.1.5 Reservoirs ("pools")

As shown in Table 1.1-3, gas is stored in a single reservoir in most of the facilities and more than one reservoir in some of the facilities. DOGGR's production and injection databases list pool names and codes. As defined by DOGGR, the pool "corresponds with the reservoir name" (http://www.conservation.ca.gov/dog/Pages/Well-Search.aspx). Geologically some of these actually consist of more than one reservoir, such as individual sands within the Tulare. This section follows DOGGR's definition of reservoir as equivalent to pool.

DOGGR's production and injection databases do not specify which reservoir is used for storage in some of the facilities, but the reservoirs utilized in these facilities are apparent from California Division of Oil and Gas (DOG, 1982; 1992; DOGGR, 1998).

Table 1.1-3. Reservoirs ("pools") in which gas is stored in each facility, along with original resource type, discovery year, and geologic information.

Field	Area[1]	Pool[1]	Type[2]	Discovered[2]	Formation[2]	Age[2]	Trap[2]
Aliso Canyon	Any	Sesnon-Frew	Oil	1940	Modelo-Llajas	Miocene-Eocene	Fault, structural
Gill Ranch Gas	Any	1st Panoche	Gas	1956	Panoche	Late Cretaceous	Structural, fault
		2nd Panoche	Gas	1989	Panoche	Late Cretaceous	Structural, fault
Honor Rancho	Southeast	Wayside 13	Oil	1956	Modelo	Late Miocene	Stratigraphic
Kirby Hill Gas	Main	Domengine	Gas	1945	Domengine	Eocene	Fault
		Wagenet	Gas	1945	Martinez	Paleocene	Fault
La Goleta Gas	Any	Vaqueros	Gas	1932	Vaqueros	Early Miocene	Structural, fault
Lodi Gas	Any	Domengine	Gas	1943	Domengine	Eocene	Structural
		Midland	Gas	1953	Mokelumne River	Late Cretaceous	Structural
Los Medanos Gas	Main	Main Block-Domengine (Domengine)	Gas	1959	Domengine	Eocene	Structural
McDonald Island Gas	Any	No Pool Breakdown	Gas	1936	Mokelumne River	Late Cretaceous	Structural, fault, stratigraphic
Montebello	West	8th	Oil	1939	Puente	Late Miocene	Structural

1 As per DOGGR's production and injection database

2 DOG (1982; 1992); DOGGR (1998); note U.S. EIA (2016) lists Wagenet pool as an "aquifer" in recent years and a "depleted field" in previous years

Field	Area[1]	Pool[1]	Type[2]	Discovered[2]	Formation[2]	Age[2]	Trap[2]
Playa del Rey	Del Rey Hills	No Pool Breakdown (Lower)	Oil	1931	Puente	Late Miocene	Stratigraphic
Pleasant Creek Gas	Any	Peters	Gas	1948	Winters	Late Cretaceous	Stratigraphic
Princeton Gas	Main	Kione	Gas	1953	Kione	Late Cretaceous	Structural, stratigraphic
Wild Goose Gas	Any	No Pool Breakdown	Gas	1951-1963	Kione	Late Cretaceous	Structural

1 As per DOGGR's production and injection database

2 DOG (1982; 1992); DOGGR (1998); note U.S. EIA (2016) lists Wagenet pool as an "aquifer" in recent years and a "depleted field" in previous years

Table 1.1-3 lists the type of trap that forms each storage reservoir. All the traps used for storage in California involve a rock type that is sufficiently permeable to support prior economic production of the oil or gas present (the reservoir or pool), overlain by a rock type that has sufficiently small pores (the caprock or seal) to preclude entry of oil or gas below a particular pressure, or sufficiently low permeability to preclude the passage of all gas or oil out of the trap. The first is termed capillary trapping, and is operative at the microscopic level in all the California storage traps. At the macroscopic level, the three main types of traps used for storage in California are structural, fault, and stratigraphic. Appendix 1.A has further information about these trap types as they occur in the UGS facilities.

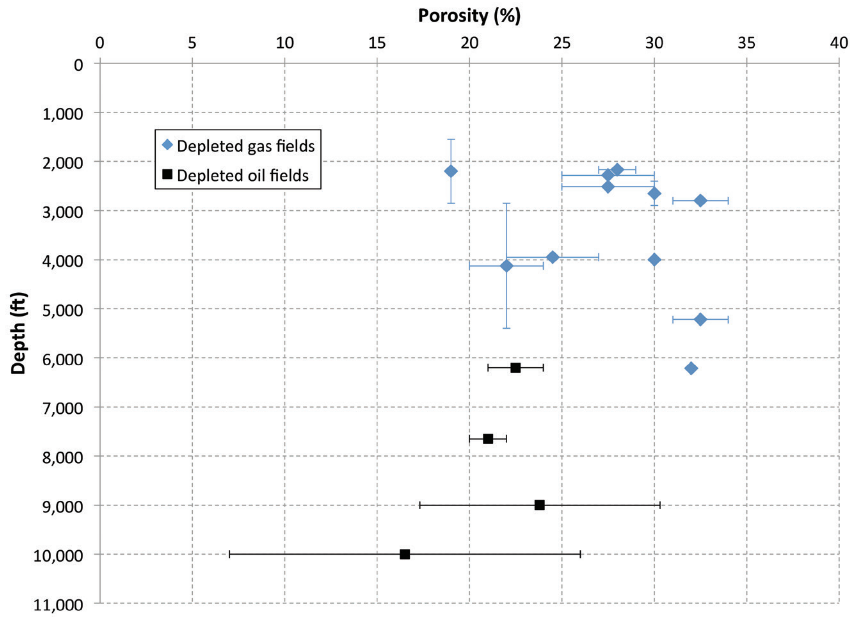
In general, the trapping of hydrocarbons over geologic time provides a basis for assuming reservoir integrity of UGS. Because all of California's UGS reservoirs are in DHRs, there is a reason to believe the natural system will provide greater sealing capacity and reservoir integrity than storage in any other geologic setting. On the other hand, the prior use of these reservoirs for oil or gas production left legacy wells in various states of use and abandonment. As discussed in Section 1.2, wells are the main concern for leakage from the subsurface components of UGS facilities. Prior use of these reservoirs, as well as use for gas storage, can also cause damage to the caprock. This reduces the integrity of the original system with regard to retention of buoyant fluids, such as stored gas. For example, injecting at too high a pressure can create transmissive fractures through the caprock. See Section 1.3 for further discussion.

Quantitative properties of each reservoir used for storage as of 2015 are listed in Table 1.1-4. The distribution of porosity and permeability with depth are shown in Figure 1.1-6. The oil reservoirs used for gas storage are deeper than the gas reservoirs. The porosity and permeability of the former oil reservoirs are lower than those of the gas reservoirs, as is typical for sedimentary reservoirs at greater depths, owing to greater consolidation as well as secondary effects, such as cementation.

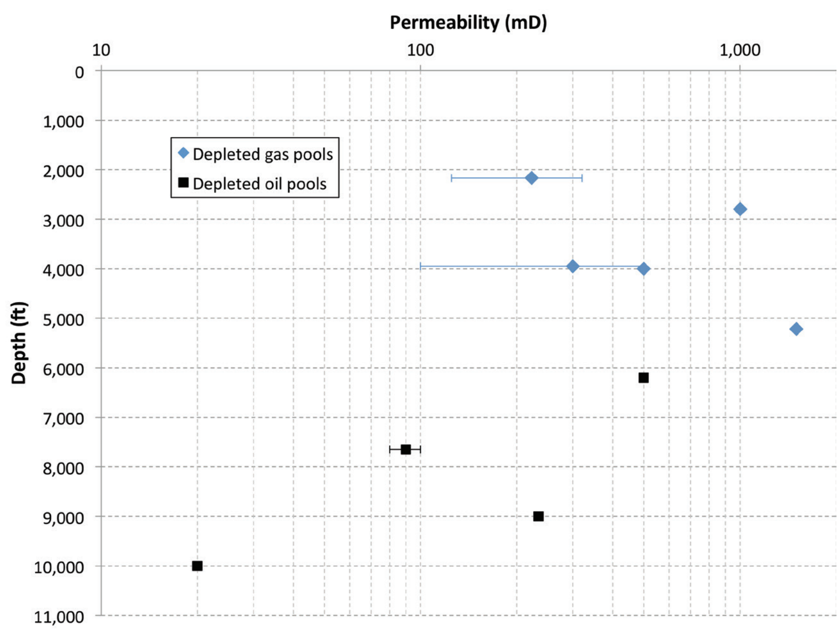
Table 1.1-4. Quantitative data regarding reservoirs ("pools") in which gas was stored as of 2015 (DOG, 1982, and DOGGR, 1992 and 1998). Tubing wellhead pressure statistics are for the 2006 to 2015 study period discounting reported zero pressures.

Field	Area	Pool	Depth (ft)	Porosity (%)	Permeability (mD)	Initial temperature (° F)	Pressure (psi)			
							Initial	Tubing wellhead		
								2.5th	Median	97.5th
Aliso Canyon	Any	Sesnon-Frew	9000	17.3-30.3	234	175	3595	210	2280	2843
Gill Ranch Gas	Southeast	1st Panoche	5850	NA	NA	128	2610	1636	2322	2556
		2nd Panoche	6216	32	NA	140	2777	1804	2399	2715
Honor Rancho	Southeast	Wayside 13	10000	7-26	20	190	4500	75	2730	3401
Kirby Hill Gas	Main	Domengine	1550-2850	19	NA	97-112	1195	456	1019	1321
		Wagenet	2850-5400	20-24	NA	110-140	2205	475	1560	1985
La Goleta Gas	Any	Vaqueros	3950	22-27	100-500	140-155	1840-2000	1311	1676	1840
Lodi Gas	Any	Domengine	2280	25-30	NA	92	987	482	846	1056
		Midland	2515	25-30	NA	93	1093	570	931	1154
Los Medanos Gas	Main	Main Block-Domengine (Domengine)	4000	30	500	112	1760	689	1390	1579
McDonald Island Gas	Any	No Pool Breakdown	5220	31-34	1500	142	2350	13151	18501	20631
Montebello	West	8th	7650	20-22	80-100		NA	14	63	470
Playa del Rey	Del Rey Hills	No Pool Breakdown (Lower)	6200	21-24	500	210	2750	23	1370	1476
Pleasant Creek Gas	Any	Peters	2800	31-34	1000	107	1270	944	1206	1238
Princeton Gas	Main	Kione	2170	27-29	125-320	85	1015	384	1080	1354
Wild Goose Gas	Any	No Pool Breakdown	2400-2900	30	NA	82-105	1105-1500	120	1251	1466

1 Casing pressure because tubing pressures other than 0 were reported for fewer than 2% of the well months in the study period



(a)

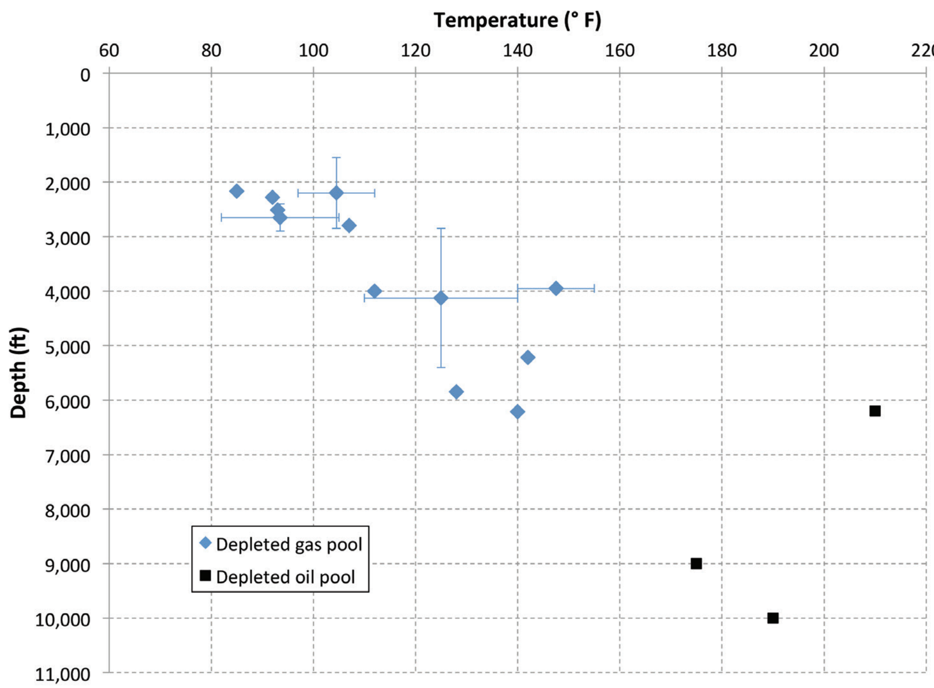


(b)

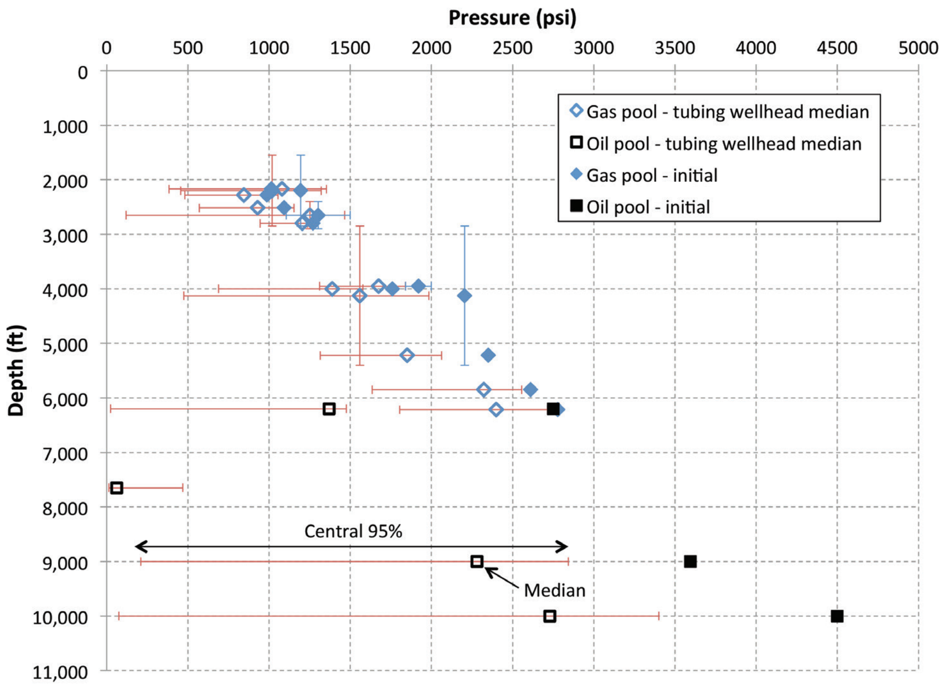
Figure 1.1-6. Depth versus (a) porosity and (b) permeability for gas storage pools in use as of 2015 (DOG, 1982, 1992; DOGGR, 1998).

Figure 1.1-7 shows the initial temperature and pressure of the reservoirs used for storage as of 2015, as well as statistics for tubing wellhead pressures from 2006 to 2015. Tubing wellhead pressure statistics are not shown for McDonald Island, because only a small portion of the well-month combinations have wellhead tubing pressure reported.

Not surprisingly, initial temperatures and pressures in the former oil reservoirs are higher because they are deeper. The operating pressures in the former oil reservoirs are significantly lower relative to the initial pressures than in the gas reservoirs. This may result from residual oil saturation in the former oil reservoirs effectively lowering the permeability to gas in those reservoirs, as compared to the lack of such interference from residual saturation in the gas reservoirs. The consequence of this is that leakage via geologic pathways (e.g., along faults) and induced seismicity are less likely in the facilities in former oil reservoirs than in former gas reservoirs. This is not to imply that leakage or induced seismicity are likely due to storage in former gas reservoirs, because the highest injection pressures are below the fracture pressure, and below the initial pressure as well for pools deeper than 2700 ft, as shown in Figure 1.1-7.

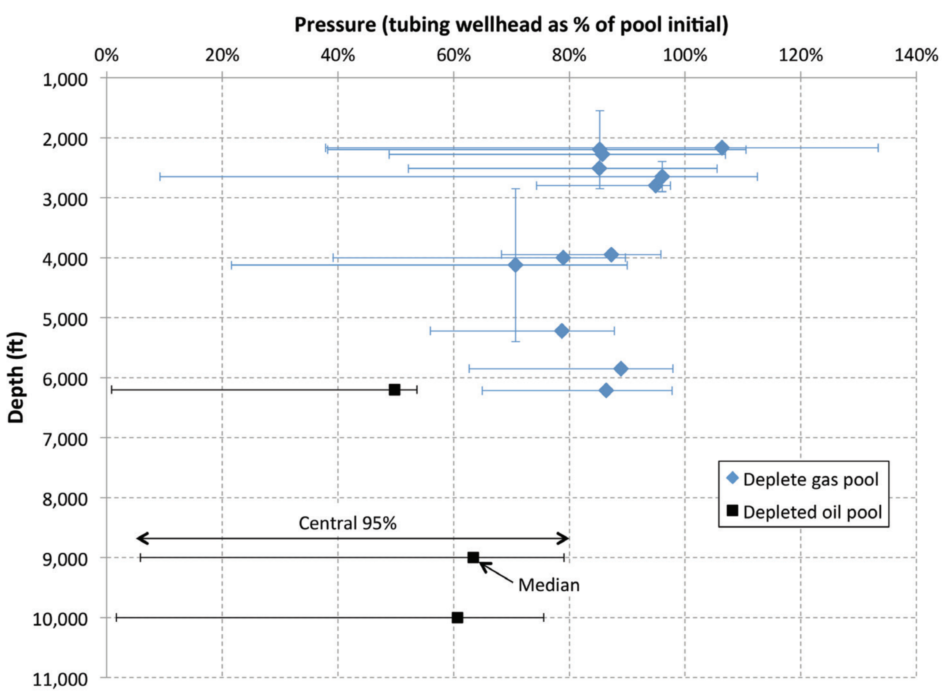


(a)



Pressure (psi)
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
Depth (ft)
0
1,000
2,000
3,000
4,000
5,000
6,000
7,000
8,000
9,000
10,000
11,000
Gas pool - tubing wellhead median
Oil pool - tubing wellhead median
Gas pool - initial
Oil pool - initial
Central 95%
Median

(b)



Pressure (tubing wellhead as % of pool initial)
0%
20%
40%
60%
80%
100%
120%
140%
Depth (ft)
1,000
2,000
3,000
4,000
5,000
6,000
7,000
8,000
9,000
10,000
11,000
Deplete gas pool
Depleted oil pool
Central 95%
Median

(c)

Figure 1.1-7. Depth versus (a) initial temperature, (b) initial pressure and tubing wellhead pressures, and (c) tubing wellhead pressures as a % of initial pressure for gas storage pools in use as of 2015 (DOG, 1982; DOGGR, 1992 and 1998).

1.1.6 Gas Storage Wells

Wells involved in gas storage were identified as any wells assigned to gas storage pools in the 2006 to 2015 DOGGR production and injection databases, without regard to well type. Wells assigned to these pools were predominantly of type GS (gas storage), but also of type OG (oil and gas production) along with a few of other types.

Table 1.1-5 shows the count of wells connected to gas storage pools in 2015 by the decade each well was spudded (drilling commenced). Spud dates are considered rather than well completion or work-over dates for several reasons. The meaning of spud date is more consistent than well completion date. This is because various activities can follow installation of the most critical components for well integrity, for instance well stimulation. Consequently, the spud date may be closer in time to when the critical components were installed, but even if it is not, its meaning is clearer. Of course, this would be irrelevant if the spud date were typically much earlier than the date(s) on which the critical components were installed. However, well completion dates are typically within a few weeks to a few months after the spud date. As gas storage wells have been installed in California across almost a century, as discussed below, the time spans of interest between wells is years to decades rather than weeks or months. With regard to work-over dates, the original well construction date is more relevant for gas storage wells in California because, as discussed below, pressure data suggest they were all withdrawn or injected through annulus between the tubing and production casing, as well as via the tubing. Consequently, the production casing and cement between that casing and the wall of the boring are the most important components for preventing leakage. It is rare that both of these are completely replaced, and such replacement is not known to have occurred in any gas storage wells in California.

Almost all the wells in former gas reservoirs were spudded in the same decade as storage commenced or later. In contrast, more than half the storage wells in former oil reservoirs were spudded in decades prior to the decade in which storage commenced. The wells in the independently operated facilities are the newest, because they are all in former gas fields and storage operations commenced later than in the other facilities. The other facilities commenced operation around the middle of the 20th century. The wells in PG&E's facilities were generally installed in the decade storage operations commenced or shortly after. In contrast, most of the wells in southern California were spudded for oil production prior to commencement of storage operations and are therefore older than the storage wells in northern California. These wells were repurposed for gas storage. More than 20% of the wells in southern California were spudded about 80 years ago, and one well was spudded about 90 years ago. Age alone does not appear to be a primary causal factor in chronic well leakage, but age can play a role in capacity and injectivity of the reservoir (see Section 1.3).

Rather, well leakage correlates with various well construction features, such as deviation from vertical and extent of cementing (Watson and Bachu, 2007). Because DOGGR does not have a database of such features, however, they are not analyzed in this report. Age also does not correlate to blowouts from inactive wells. It does correlate to blowouts from active wells perhaps, because it correlates to the amount of mechanical work done on the well by production and injection (Jordan and Carey, 2016), as discussed further below.

Table 1.1-5. Count of wells connected to (perforated or screened in) gas storage pools in 2015 by spud decade (NA = spud date not available). Pink highlighting indicates more than 50% of the wells in the field or total were spudded in that decade. Orange indicates 25% to 50% and yellow indicates 10% to 25%. Boxed decades indicate when gas storage commenced in each field.

Field	**# of wells spudded in decade**										
	NA	**1920s**	**1930s**	**1940s**	**1950s**	**1960s**	**1970s**	**1980s**	**1990s**	**2000s**	**2010s**
Gill Ranch Gas											12
Kirby Hill Gas[1]							3			12	3
Lodi Gas				1	1					22	2
Princeton Gas					1	1		1		2	8
Wild Goose Gas									3	10	4
Independents	0	0	0	1	2	1	3	1	3	46	29
Los Medanos Gas							14		6	1	
McDonald Island Gas			2	4		6	61	6	9		
Pleasant Creek Gas				2			4				1
PG&E	0	0	2	6	0	6	79	6	15	1	1
North	0	0	2	7	2	7	82	7	18	47	30
Aliso Canyon			1	33	20		33	8	9	9	2
Honor Rancho	1				16	3	16		1	1	3
La Goleta Gas		1	3	4	6		4				
Playa del Rey	3		41			3		3		4	
South/SoCalGas	4	1	45	37	42	6	53	11	10	14	5
Total	4	1	47	44	44	13	135	18	28	61	35

1 Because storage in the Wagenet pool commenced in 2008, and there are almost the same number of wells in the Domengine pool, nine years was used as the basis.

Table 1.1-6 shows the average volume of gas transferred annually (injected plus withdrawn) by well spud decade during the study period. A higher proportion of gas was transferred via wells spudded prior to commencement of storage in former oil reservoirs than gas reservoirs. A substantially higher portion of gas transferred in southern California was via older wells than in northern California. This was most pronounced in the Playa del Rey field, where more than four fifths of the gas transferred was via wells spudded in the 1930s. In contrast, gas transferred at the independent facilities was via much newer wells constructed for storage. As shown in Table 1.1-5, older wells were still in use as of 2015.

Table 1.1-6. Average gas transferred (sum of injected and withdrawn) annually from 2006 to 2015 by spud decade (NA = spud date not available). Pink highlighting indicates more than 50% of the gas transferred was via wells spudded in that decade. Orange indicates 25% to 50% and yellow indicates 10% to 25%. Boxed decades indicate when gas storage commenced in each field.

Field	Average gas transferred annually by well spud decade (Bcf)										
	NA	1920s	1930s	1940s	1950s	1960s	1970s	1980s	1990s	2000s	2010s
Gill Ranch Gas											9.4
Kirby Hill Gas[1]							3.0			15.6	1.1
Lodi Gas										40.4	3.2
Princeton Gas											4.7
Wild Goose Gas									12.8	29.7	7.3
Independents							3.0		12.8	85.6	25.6
Los Medanos Gas							14.4		5.3	0.0	
McDonald Island Gas			1.2	1.3		6.2	49.8	5.3	8.7	0.1	
Pleasant Creek Gas				0.7			1.5				0.3
PG&E			1.2	2.0		6.2	65.6	5.3	14.0	0.1	0.3
North			1.2	2.0		6.2	68.7	5.3	26.8	85.7	26.0
Aliso Canyon			0.0	24.7	9.4	0.1	47.3	7.2	16.3	11.1	0.2
Honor Rancho	1.0				22.1	1.5	25.7		2.1	0.0	
La Goleta Gas		1.8	4.2	5.8	6.3		5.9				
Playa del Rey			5.9			0.0		1.3		0.5	
South/SoCalGas	1.0	1.8	10.1	30.5	37.7	1.7	78.9	8.5	18.4	11.5	0.2
Total	1.0	1.8	11.3	32.5	37.7	7.9	147.5	13.9	45.2	97.3	26.2

1 Because storage in the Wagenet pool commenced in 2008, and there are almost the same number of wells in the Domengine pool, nine years was used as the basis.

Table 1.1-7 shows that the average volume of gas transferred (injected and withdrawn) per well per month gas was transferred by spud decade. The wells in the independent facilities have higher average gas transferred per month they are operating than do wells in PG&E's facilities. These wells were built for storage. The average gas transferred per month via wells constructed before storage is relatively constant across PG&E's facilities and those in southern California. Particularly noteworthy is the moderate average monthly flow through a well spudded in the 1920s, along with moderate flow via wells spudded in the 1930s in the McDonald Island Gas and La Goleta Gas facilities.

Table 1.1-7. Average volume of gas transferred (sum of injected and withdrawn) per well per month gas was transferred during 2006 to 2015 by spud decade ((NA = spud date not available)). Pink highlighting indicates more than 250 million scf of gas transferred per well per month on average. Orange indicates 100 to 250 million scf and yellow indicates 20 to less than 100 million scf per month. Boxed decades indicate when gas storage commenced in each field. Averages are weighted by the number of wells performing transfers.

Field	**Average gas transferred per well month by spud decade (million scf)**										
	NA	**1920s**	**1930s**	**1940s**	**1950s**	**1960s**	**1970s**	**1980s**	**1990s**	**2000s**	**2010s**
Gill Ranch Gas											150
Kirby Hill Gas[1]							53			89	7
Lodi Gas										537	315
Princeton Gas											78
Wild Goose Gas									1326	1037	94
Independents							53		1326	527	119
Los Medanos Gas							261		282	3	
McDonald Island Gas			0.1	1		64	90	51	38	5	
Pleasant Creek Gas				5			36				1
PG&E			0.1	3		64	118	51	129	4	1
North			0.1	3		64	116	51	318	488	115
Aliso Canyon			20	144	102	0.1	213	44	708	226	2
Honor Rancho	128				397	66	161		25	0.5	
La Goleta Gas		16	90	303	159		394				
Playa del Rey			14			0.2		24		4	
South/SoCalGas	128	16	22	164	230	29	211	39	640	157	2
Average	128	16	11	153	230	46	154	43	429	407	111

1 Because storage in the Wagenet pool commenced in 2008, and there are almost the same number of wells in the Domengine pool, nine years was used as the basis.

Figure 1.1-8 shows the percent of total gas transferred during the study period via each well versus that well's spud date. It also indicates the ratio of withdrawal and injection at each well. As indicated above, wells used in the Playa del Rey field were predominantly spudded in the 1930s. Figure 1.1-8 indicates most of those wells had similar volumes of gas injected as withdrawn. The wells spudded longest ago are in the La Goleta field, and also had similar volumes of gas injected as withdrawn. Study of steam flood versus cyclic steam wells finds the latter blowout after a significantly smaller volume of fluid transferred than the former, perhaps because more mechanical work is done on the latter as a result of switching frequently between injection and withdrawal. The blowout rate per fluid volume transferred was five times higher for cyclically operated relative to continuously operated wells, which was significant (Jordan and Benson, 2009). It is unknown if this difference exists for gas storage wells operated cyclically versus continuously. It is suggestive that SS-25 in the Aliso Canyon facility was one of the few old wells that was operated cyclically. Most other wells of the same vintage were used only for withdrawal.

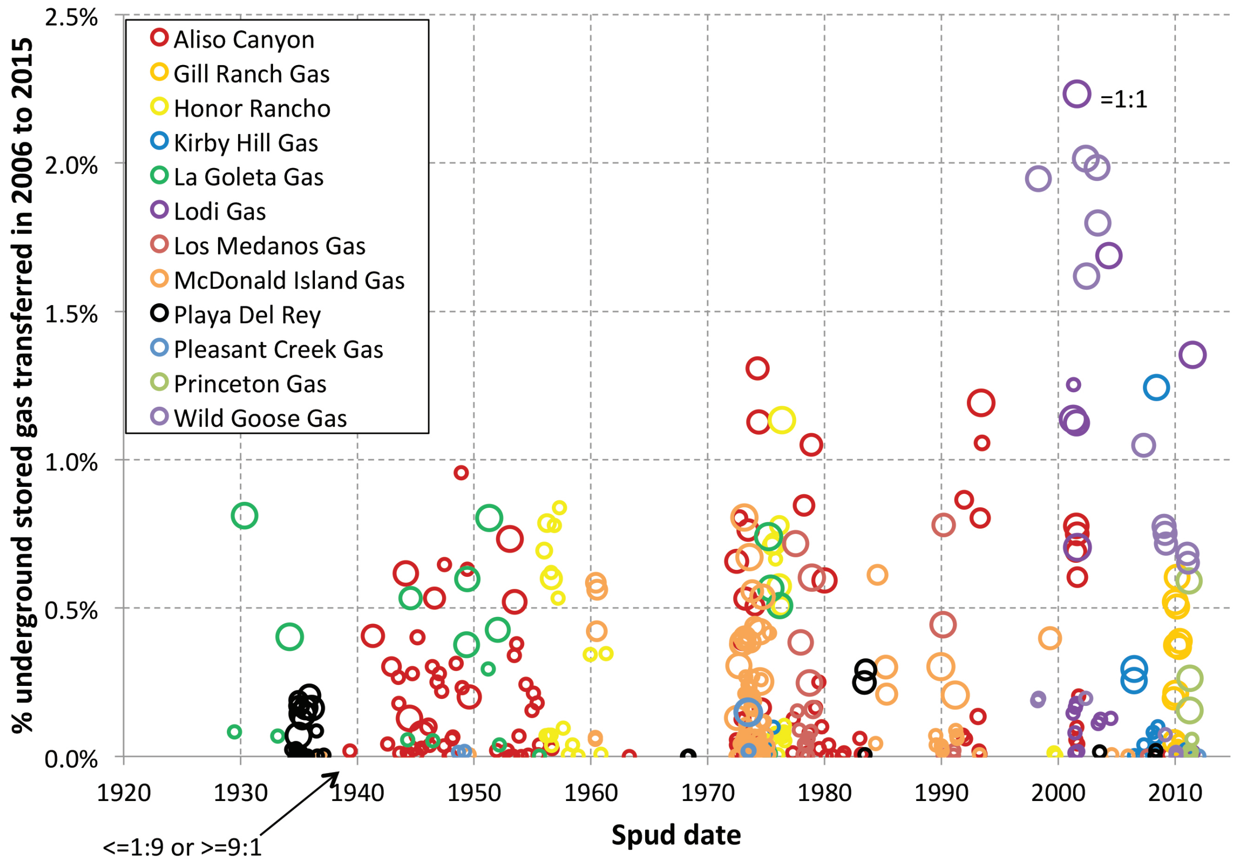
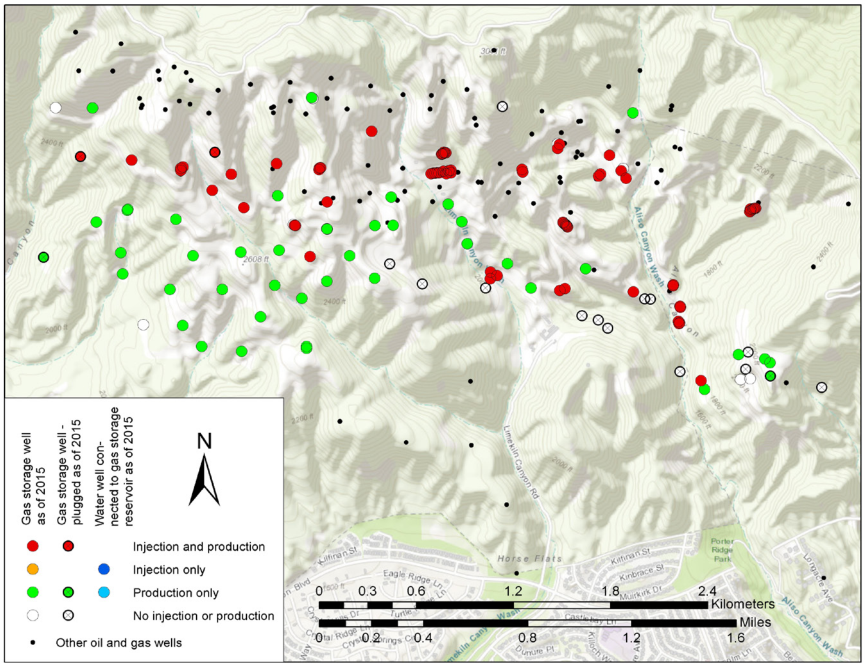
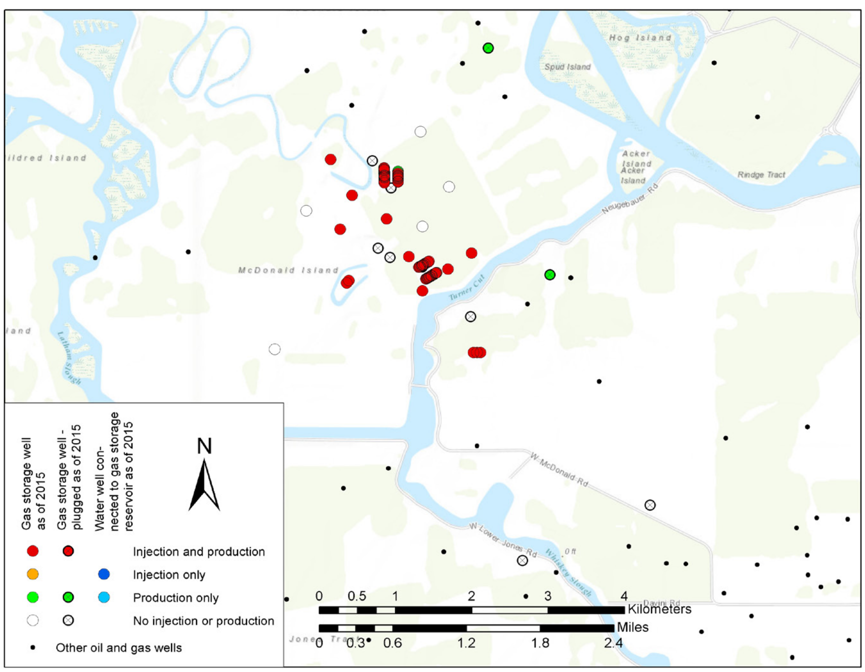


Figure 1.1-8. Percent of total gas transferred via each well versus its spud date. The size of the symbol indicates the ratio of withdrawal and injection in each well, with larger symbols indicating more equal injection and withdrawal.

The wells vary from vertical to directional. Wellheads for the former are necessarily dispersed, while the latter are typically clustered. There is a higher proportion of wells that predate storage in former oil reservoirs than gas reservoirs, and consequently a higher proportion of vertical wells, as shown in Figure 1.1-9. This is in indicated by the more dispersed wellhead locations at Aliso Canyon than at McDonald Island, even though they have similar capacities and number of wells, and drilling one well per pad at Aliso Canyon is more expensive than at McDonald Island due to the contrast in topographic relief. This expense was born during the development of oil production in Aliso Canyon, because directional drilling technology was not economically competitive at that time. Some of the wells that predate storage in former oil reservoirs were used solely for withdrawal as of 2015, while a smaller portion of wells in former gas reservoirs are operated in this manner.



(a)



(b)

Figure 1.1-9. Gas storage well use during 2006 to 2015, status as of 2015, and wellhead locations in (a) the Aliso Canyon field and (b) the MacDonald Island Gas field along with locations of oil and gas production-related wells. The latter may be active (meaning producing), idle, or abandoned (generally plugged).

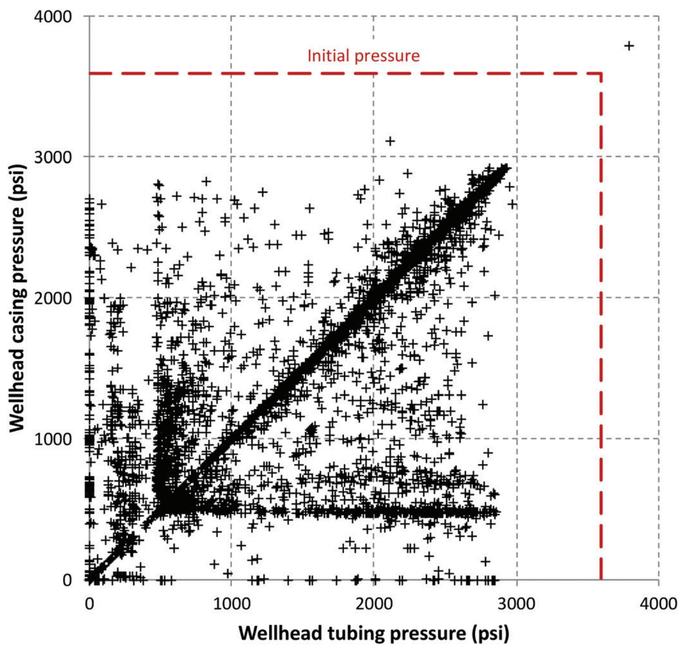
The wellhead locations shown in Figure 1.1-9 are those in DOGGR's AllWells Gridpoint Statistical Interpolation (GIS) layer. However, the field area in this layer is different from that listed in DOGGR's production and injection database for some wells identified as involved in gas storage. Examples are shown in Table 1.1-8

Table 1.1-8. Example wells listed in a different area in DOGGR's production and injection database (pro/inj db) than in its AllWells GIS layer.

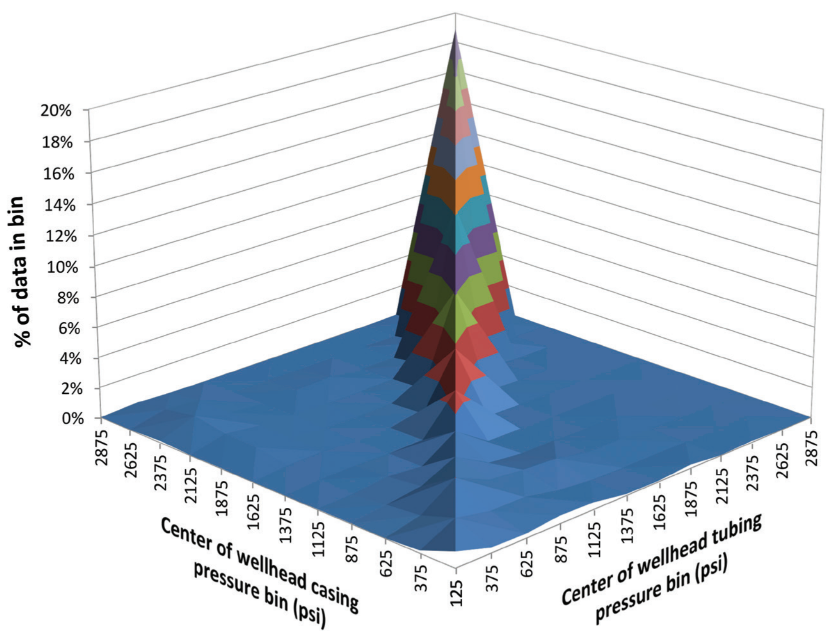
API #	Field	Area	
		Pro/inj db[1]	**AllWells**
03714015	Playa del Rey	Del Rey Hills	Venice
03712719	Montebello	West	Main
03707615	Honor Rancho	Southeast	Main

The blowout of well SS-25 in the Aliso Canyon facility (2015 Aliso Canyon incident) was at least partially due to withdrawal and injection through the production casing, as well as the tubing (refer to the side bar regarding this blowout for a discussion of why injection and withdrawal through the production casing was a substantial contributing factor to the event). As such, the full injection and withdrawal pressure, and the swings between the two, were imposed on the production casing, which is the outermost casing over most of the length of the well. This both imposes work (deformation caused by pressure) on this casing and the surrounding cement seal, where present, along with resulting in a blowout if this single barrier should fail. In order to assess how common this well configuration and operation was across UGS wells in California, the monthly casing and tubing pressures in DOGGR's production database for the study period were compared.

Setting aside for now the reported zero tubing wellhead pressures, most casing wellhead pressures are 90% to 110% of tubing wellhead pressures in DOGGR's production database for the study period. For example, Figure 1.1-10 shows the monthly casing versus tubing wellhead pressures in Aliso Canyon UGS wells for the study period in DOGGR's production database. This indicates that both the tubing and the annulus between the tubing and the production casing are connected to the storage reservoir. A review of a sample of well records suggests this is likely via sliding sleeve valves (SSVs) installed in most wells a short distance above the packer. The packer is the seal between the tubing and production casing, typically a relatively short distance above the portion of the well connected to the storage reservoir.



(a)



(b)

Figure 1.1-10. Monthly wellhead casing versus tubing pressure in the Aliso Canyon storage facility from the DOGGR production database for 2006 through 2015: (a) data and initial storage zone pressure (note that data are at wellhead while initial pressure is in the storage reservoir), (b) and % histogram.

The occurrence of high casing pressures with zero tubing pressure shown in Figure 1.1-10 appears likely to be inaccurate. A zero tubing pressure would indicate either complete pressure depletion in the storage reservoir or closure of a valve in between the reservoir and the tubing pressure gage on the wellhead. The former is not possible in a facility that still stores working gas. A review of the records for one well with such a reported pressure combination, API# 0370072, indicates a zero tubing pressure is unlikely to be possible, and is unlikely to be possible in combination with a high casing pressure.

The well API# 0370072 has tubing. The record does not indicate there is a valve to close the tubing between the storage reservoir and the wellhead. The annulus between the tubing and production casing is sealed by a packer above the interval connected to the reservoir in which gas is stored. Consequently, it does not appear possible to have pressures in the annulus indicative of storage reservoir pressures at the same time as zero pressure in the tubing.

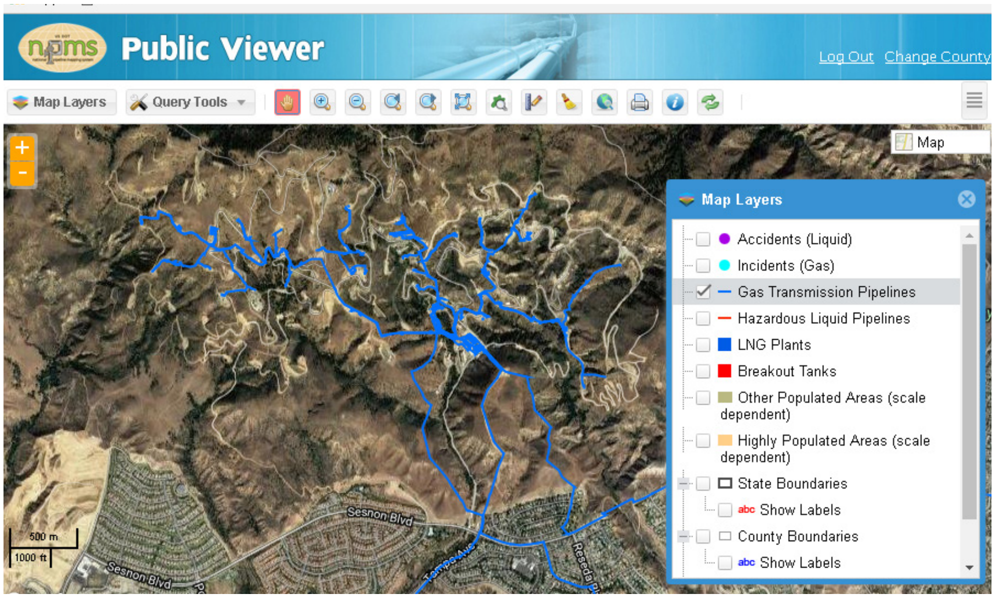
The same casing pressure is reported to four significant digits (2447 psi) from August 2008 through April 2009. Given the variation in the gas stored in the facility during this time, and the number of significant figures in the reported data, it seems unlikely these data are accurate. Given both of these findings (likely inaccuracy of reported zero tubing pressures and repeated casing pressure values from month to month), the data cannot be taken as accurate for any particular well. However, in aggregate, these problems are sufficiently infrequent that the overall findings are accurate regarding pressures, and the well configuration they imply.

1.1.7 Surface Infrastructure

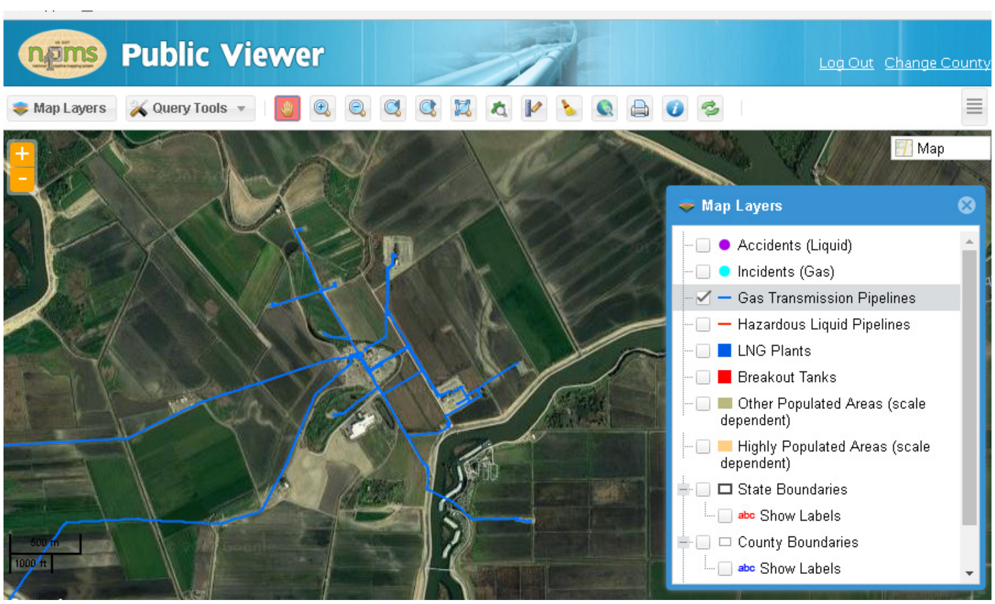
As shown in Figure 1.0-1., gas storage facility infrastructure consists of the pipeline between the transmission pipeline and the facility, termed the interconnect in this report; the gas handling plant(s), consisting primarily of compressors, expanders, and processing units; and pipelines between the gas handling plant(s) and the wells, termed flowlines in this report. Fewer data are publicly available regarding this surface infrastructure than the subsurface infrastructure at gas storage facilities. This includes data on both the configuration of the infrastructure and its operation.

The public can view the location of natural gas transmission pipelines through the National Pipeline Mapping System (pipelines distributing gas to customers, such as to residences, are distribution rather than transmission pipelines, and so are not shown). However, the public viewer only shows the pipelines in views with scale smaller than 1:50,000. It also does not provide for downloading the pipeline location data, which are needed for performing analysis.

The precise location data are available to "government officials and pipeline operators" as stated on the home page of the National Pipeline Mapping System. As such, some of the government employee members of the team conducting this independent scientific assessment applied for and were provided these data under the condition that they not share the data in raw form nor publicize more detailed images than available on the public viewer. Figure 1.1-11 shows examples of the pipeline maps at storage facilities from the public viewer.



(a)



(b)

Figure 1.1-11. Sample map views of underground gas storage facilities at the highest resolution available: (a) Aliso Canyon, and (b) MacDonald Island.

The pipeline location data appear complete in terms of the sources and flowlines, with two caveats and two exceptions. The first caveat is that only one flowline is generally shown to each well pad, whereas there may actually be two, one for injection and one for withdrawal. The second caveat is that almost none of the flowlines from the edge of well pads or manifolds to the actual wellhead is included. The two exceptions are that the data do not include flowlines to some of the well manifolds and pads in the Aliso Canyon, Honor Rancho, and Playa del Rey fields. Conversely, all the SoCalGas facilities and none of the others show pipeline locations within the gas handling plants.

Table 1.1-9 lists the total source and field pipeline lengths available in the National Pipeline Mapping System data as provided in spring 2017. The independently operated facilities have the highest average pipeline length per capacity and average gas transferred. This is primarily owing to long source pipelines. The other two facilities with the most pipeline per capacity and average gas transferred are the smallest facilities in northern and southern California. For these facilities, the high ratios result primarily from the amount of flowlines.

Table 1.1-9. Source and field pipeline lengths from the National Pipeline Mapping System as of spring 2017. Lengths per capacity and average annual gas transferred (sum of injected and withdrawn) are also provided. Pipeline to capacity and average annual gas transferred ratios greater than one mi./Bcf are highlighted in pink, between 0.5 and one mi./Bcf in orange, and between 0.2 and 0.5 mi./Bcf in yellow.

Field	2015 capacity (Bcf)	Average annual transferred 2006-2015 (Bcf)	Pipeline length (mi.)			By capacity (mi./Bcf)			By transferred (mi./Bcf)		
			Field1	Source	Total	Field	Source	Total	Field	Source	Total
Gill Ranch Gas	20.0	18.9	5.0	26.4	31.4	0.25	1.32	1.57	0.26	1.40	1.66
Kirby Hill Gas	15.0	21.9	1.9	5.7	7.6	0.13	0.38	0.51	0.09	0.26	0.35
Lodi Gas	17.0	43.6	6.2	30.2	36.4	0.36	1.78	2.14	0.14	0.69	0.84
Princeton Gas	11.0	11.6	1.1	14.1	15.2	0.10	1.28	1.38	0.09	1.21	1.31
Wild Goose Gas	75.0	49.7	12.6	24	36.6	0.17	0.32	0.49	0.25	0.48	0.74
Total - independents	138.0	145.7	26.8	100.4	127.2	0.19	0.73	0.92	0.18	0.69	0.87
Los Medanos Gas	17.9	19.7	1.7	0.2	1.9	0.09	0.01	0.11	0.09	0.01	0.1
McDonald Island Gas	82.0	72.6	6.2	18.4	24.6	0.08	0.22	0.30	0.09	0.25	0.34
Pleasant Creek Gas	2.3	2.4	2.1	0.6	2.7	0.93	0.27	1.20	0.87	0.25	1.12
Total - PG&E	102.2	94.7	10.0	19.2	29.2	0.10	0.19	0.29	0.11	0.20	0.31
Total - N.	240.2	240.4	36.8	119.6	156.4	0.15	0.50	0.65	0.15	0.50	0.65
Aliso Canyon*	86.2	116.3	15.9	3.7	19.6	0.18	0.04	0.23	0.14	0.03	0.17
Honor Rancho*	27.0	51.4	6.1	0.2	6.3	0.23	0.01	0.23	0.12	0.00	0.12
La Goleta Gas	19.7	24.0	4.3	0	4.3	0.22	0.00	0.22	0.18	0.00	0.18
Playa del Rey*	2.4	7.7	4.7	2.5	7.2	1.96	1.04	3.00	0.61	0.32	0.93
Total - S. (SoCalGas)	135.3	199.4	31.0	6.4	37.4	0.23	0.05	0.28	0.16	0.03	0.19
Total	375.5	439.8	67.8	126.0	193.8	0.18	0.34	0.52	0.15	0.29	0.44

*Flowlines to some well manifolds or pads were not available in the data, so the flowline total shown is smaller than actual

1 Only a single flowline shown between the handling facility and each well manifold or pad typically shown in the data, whereas there is some evidence for separate injection and withdrawal lines to each. So totals may be systematically only roughly half of the actual flowline length. Pipelines with gas handling facilities, available for some facilities, are not included. Pipelines from manifolds or the edge of well pads to wellheads generally not included in NPMS GIS layer.

While the National Pipeline Mapping System data table has fields for diameter, this field was empty for most of the pipelines associated with storage facilities. There was no data field for other relevant physical attributes, such as pipeline material and year of installation. We did not find any such data available from any other source.

We did not identify any data source listing the locations of gas handling plants in each storage facility. However, we identified their location using aerial imagery, such as that visible in Figure 1.1-11. This was facilitated by use of the pipeline location data as the gas handling plants sit between the connection and flowlines typically.

Table 1.1-10 lists the position of the gas handling facilities relative to the storage well fields. The average distance between the handling plants and the edge of the well field is more than an order of magnitude greater for the independently operated facilities than for the others. The average distance of PG&E and SoCalGas's gas handling plants from the associated well field is the same small value. Closer proximity between the gas handling plant, which includes the operation center, and the well field increases the risk that an incident with one can negatively impact the other. For instance, a well blowout near an operations center could require the evacuation of that center and require shutdown of gas handling equipment (such as compressors) to reduce the likelihood of an explosion. More discussion of fire and explosion hazard and risk is provided in Sections 1.2 and 1.4.

Table 1.1-10. Distance and direction from the edge of the storage well field to the gas handling plant in each facility. Zero indicates the handling plant is within the well field.

Field	Handling plant center to well field edge	
	Distance (km)	Direction
Gill Ranch Gas	0	-
Kirby Hill Gas	0.7	SW
Lodi Gas	6.5	W
Princeton Gas	0.9	N
Wild Goose Gas	8	NE
Average - independents	3.2	-
Los Medanos Gas	0.3	E
McDonald Island Gas	0	-
Pleasant Creek Gas	0.4	E
Average - PG&E	0.2	-
Aliso Canyon	0.2	S
Honor Rancho	0	-
La Goleta Gas	0.5	NE
Playa del Rey	0	-
Average - SoCalGas	0.2	-

1.1.8 Groundwater

Table 1.1-11 lists the minimum, estimated, and maximum number of groundwater wells of various types within DOGGR's administrative area for each gas storage reservoir based on California Department of Water Resources (DWR; 2017). This dataset lists over 900,000 wells. The DWR estimates there are one to two million groundwater wells in the state (http://water.ca.gov/groundwater/wells/index.cfm), so DWR (2017) may have data on nearly all wells to half of all wells. Consequently, the values in Table 1.1-11 are likely a bit low.

DOGGR's administrative area for each field is larger than the area underlain by the storage pools. How much larger cannot be judged precisely because the footprint of stored gas in each pool is not publicly available to our knowledge. However, DOGGR did map the known footprint of producible hydrocarbons in 1973/74, which is available as a GIS layer (ftp://ftp.consrv.ca.gov/pub/oil/GIS/Shapefiles/1973and1974ProductiveLimits.zip). For the seven field areas with storage for which this footprint is shown, the administrative area used for searching for groundwater wells was two times or less as large for five of the fields. The wellheads involved in gas storage in the study period were within the 1973/74 productive footprint for three of these, and up to tens of meters outside the footprint for the other two. The two facilities with administrative to productive area ratios larger than two have wellheads involved in storage in the study period that are hundreds of meters outside of the footprint. For these facilities, this distance was a third to a half of the equivalent radius of the productive footprint area, indicating that the productive limits have expanded substantially.

So the number of groundwater wells listed in Table 1.1-11 is greater than those that are directly overlying a gas storage pool. However, the search area is reasonable given the lateral migration potential of leaked gas.

Table 1.1-11. Estimated number of groundwater wells within DOGGR's administrative area for each gas storage pool (DWR, 2017). Well locations are by section in the data source. Minimum is the sum of wells in sections completely within the gas storage pool administrative area. Maximum is the sum of wells in all sections partially or wholly within the gas storage pool administrative area. Estimated is the sum of wells apportioned by the portion of each section within the gas storage pool administrative area. Well categories are generally arranged from most to least hazardous with regard to gas entry to the well based on the likely surface infrastructure attached to the well and proximity of people to that infrastructure. Well sums greater than 90 are highlighted in pink, 30 to fewer than 90 in orange, and ten to fewer than 30 in yellow. Blank indicates no wells. Zero indicates fewer than 0.5 wells.

		Independents					PG&E			SoCalGas				
Facility		**Gill Ranch Gas**	**Kirby Hill Gas**	**Lodi Gas**	**Princeton Gas**	**Wild Goose Gas**	**Los Medanos Gas**	**McDonald Island Gas**	**Pleasant Creek Gas**	**Aliso Canyon**	**Honor Rancho**	**La Goleta Gas**	**Playa del Rey**	**Total**
Unknown	Max.	4	18	15	1		9	33	2			13	1	96
	Est.	4	14	8	1		8	33	1			2	1	72
	Min.	4	14	5	1		4	33	0			0	1	62
Public supply	Max.			1			1	3	1		1	5		12
	Est.			0			1	3	1		0	1		5
	Min.			0			0	3	0		0	0		3
Domestic	Max.	2	8	268	12	2	11	12	6		4	31		356
	Est.	2	2	157	10	1	9	10	4		1	8		203
	Min.	2	0	75	8	1	4	6	2		0	0		98

1 Also includes air conditioning, fire or frost protection, golf course irrigation, power generation, and landscape irrigation because like industrial supply wells as these are likely to be connected to vessels in proximity to people and water from them is unlikely to be drunk

2 Also includes dewatering, injection, extraction, soil vapor extraction, sparge, remediation because like remediation wells as these are likely to be connected to vessels but in less proximity to people than the industrial category and water from them is unlikely to be drunk

		Independents					PG&E			SoCalGas				
Facility		**Gill Ranch Gas**	**Kirby Hill Gas**	**Lodi Gas**	**Princeton Gas**	**Wild Goose Gas**	**Los Medanos Gas**	**McDonald Island Gas**	**Pleasant Creek Gas**	**Aliso Canyon**	**Honor Rancho**	**La Goleta Gas**	**Playa del Rey**	**Total**
Industrial[1]	Max.				2		2					11		15
	Est.				2		2					5		8
	Min.				1		1					0		2
Remediation[2]	Max.				8							48		56
	Est.				8							3		11
	Min.				8							0		8
Stock, dairy	Max.			1										1
	Est.			0										0
	Min.			0										
Irrigation	Max.	20	1	59	19	1	1	1	11		3	4		120
	Est.	20	1	32	14	0	1	0	7		1	2		78
	Min.	20	1	18	12				3					54
Monitoring, piezometer, temporary	Max.	3	1		1	1	6	44		3	8	94	19	180
	Est.	3	1		1	1	6	42		2	4	33	7	100
	Min.	3	1		1	1	6	15		1	0	0	3	31
Instrument	Max.		1				4			3	3	4	5	20
	Est.		1				4			2	2	4	4	17
	Min.		0				4			1	0	3	4	12
Abandoned, destroyed	Max.				2									2
	Est.				2									2
	Min.				2									2
Total	Max.	29	29	344	45	4	34	93	20	6	19	210	25	858
	Est.	29	18	197	37	3	30	89	12	4	8	57	12	496
	Min.	29	16	98	33	2	19	57	5	2	0	3	8	272

1 Also includes air conditioning, fire or frost protection, golf course irrigation, power generation, and landscape irrigation because like industrial supply wells as these are likely to be connected to vessels in proximity to people and water from them is unlikely to be drunk

2 Also includes dewatering, injection, extraction, soil vapor extraction, sparge, remediation because like remediation wells as these are likely to be connected to vessels but in less proximity to people than the industrial category and water from them is unlikely to be drunk

The well types are generally listed from most to least hazardous if free gas enters the well. This ordering is based upon likely surface infrastructure attached to the well, the proximity of people, and use of the water. Public supply and domestic wells are the most likely to be connected to water storage vessels at the surface, to be located close to people, and to produce water consumed by people. The explosion hazard from accumulation of gas in these wells along with the hazard of consuming water with changed quality is highest for these wells. Between them, water from each public supply well is consumed by more people than from domestic wells, and so more people would be exposed to water quality changes due to entry of gas into the aquifer in the vicinity of a public supply wells than near a domestic well. Additional discussion of the likelihood and consequences of natural gas leakage into underground sources of drinking water (USDW) wells is provided in Section 1.2.10.

Industrial supply and remediation wells are also likely to have vessels connected to them that are in proximity to people, but the water from them is not consumed. Between them, industrial wells and associated vessels are more likely to be near people than remediation wells because some of the latter occur in relatively de-occupied brownfields undergoing remediation. Remediation, stock, and irrigation wells may have tanks or other vessels connected to them, in decreasing order of likelihood. They are also less likely to be in proximity to people, again in decreasing order of likelihood. Monitoring wells do not have tanks. While they may be in proximity to people, the total amount of energy they can release upon explosion is limited due to their limited volume. Instrument and abandoned wells likely do not have tanks or other vessels connected to them, have even smaller volumes near the ground surface for gas accumulation than the monitoring wells, and a lower likelihood of gas entering that volume.

Lodi Gas has the largest number of domestic wells by an order of magnitude and irrigation wells by a factor of two. However, the gas storage wells at this facility are clustered, like at many other facilities. Consequently, estimating the number of groundwater wells at risk of gas intrusion by using the administrative areas may overestimate the number of wells at such facilities. However, without digitizing the directional surveys for each well, defining the position of the aquifers accessed by the groundwater wells, and performing a three-dimensional spatial buffering of the gas supply wells relative to these aquifers, it is not clear that clustering at the surface translates to a smaller hazard footprint relative to the administrative area compared to facilities with numerous vertical gas storage wells. Also, the above concerns only leakage from gas storage wells. The administrative area is a more appropriate relative area for assessing the number of groundwater wells at risk of intrusion by gas leaking along geologic pathways.

While Table 1.1-11 presents estimates of the absolute number of groundwater wells, Table 1.1-12 lists the number of wells per unit of storage capacity in 2015. This provides some perspective on the risk of leakage from storage wells to groundwater relative to the benefit of storage.

Table 1.1-12. Estimated number of groundwater wells overlying gas storage pools per 2015 storage capacity (DWR, 2017). Well sums greater than nine are highlighted in pink, from three to eight in orange, and from one to two in yellow. Blank indicates no wells. Zero indicates fewer than 0.05 wells. See Table 1.1-1 for footnotes and caption for more details.

Facility		Independents					PG&E			SoCalGas				Total
		Gill Ranch Gas	**Kirby Hill Gas**	**Lodi Gas**	**Princeton Gas**	**Wild Goose Gas**	**Los Medanos Gas**	**McDonald Island Gas**	**Pleasant Creek Gas**	**Aliso Canyon**	**Honor Rancho**	**La Goleta Gas**	**Playa del Rey**	
Unknown	Max.	0.2	1.2	0.9	0.1		0.5	0.4	0.9			0.7	0.4	0.3
	Est.	0.2	0.9	0.5	0.1		0.4	0.4	0.4			0.1	0.4	0.2
	Min.	0.2	0.9	0.3	0.1		0.2	0.4	0.0			0.0	0.4	0.2
Public supply	Max.			0.1			0.1	0.0	0.4		0.0	0.3		0.0
	Est.			0.0			0.0	0.0	0.2		0.0	0.0		0.0
	Min.			0.0			0.0	0.0	0.0		0.0	0.0		0.0
Domestic	Max.	0.1	0.5	15.8	1.1	0.0	0.6	0.1	2.7		0.1	1.6		0.9
	Est.	0.1	0.1	9.2	0.9	0.0	0.5	0.1	1.7		0.0	0.4		0.5
	Min.	0.1	0.0	4.4	0.7	0.0	0.2	0.1	0.9		0.0	0.0		0.3
Industrial[1]	Max.				0.2		0.1					0.6		0.0
	Est.				0.2		0.1					0.2		0.0
	Min.				0.1		0.1					0.0		0.0
Remediation[2]	Max.				0.7							2.4		0.1
	Est.				0.7							0.2		0.0
	Min.				0.7							0.0		0.0
Stock, dairy	Max.			0.1										0.0
	Est.			0.0										0.0
	Min.			0.0										0.0
Irrigation	Max.	1.0	0.1	3.5	1.7	0.0	0.1	0.0	4.9		0.1	0.2		0.3
	Est.	1.0	0.1	1.9	1.3	0.0	0.0	0.0	3.1		0.0	0.1		0.2
	Min.	1.0	0.1	1.1	1.1				1.3		0.0	0.0		0.1
Monitoring, piezometer, temporary	Max.	0.2	0.1		0.1	0.0	0.3	0.5		0.0	0.3	4.8	7.9	0.5
	Est.	0.2	0.1		0.1	0.0	0.3	0.5		0.0	0.1	1.7	2.8	0.3
	Min.	0.2	0.1		0.1	0.0	0.3	0.2		0.0	0.0	0.0	1.3	0.1
Instrument[3]	Max.		0.1				0.2			0.0	0.1	0.2	2.1	0.1
	Est.		0.0				0.2			0.0	0.1	0.2	1.8	0.0
	Min.		0.0				0.2			0.0		0.2	1.7	0.0
Abandoned, destroyed	Max.				0.2									0.0
	Est.				0.2									0.0
	Min.				0.2									0.0
Total	Max.	1.5	1.9	20.2	4.1	0.1	1.9	1.1	8.9	0.1	0.7	10.7	10.4	2.3
	Est.	1.4	1.2	11.6	3.4	0.0	1.7	1.1	5.4	0.0	0.3	2.9	5.0	1.3
	Min.	1.5	1.1	5.8	3.0	0.0	1.1	0.7	2.2	0.0	0.0	0.2	3.3	0.7

Lodi Gas has the largest number of domestic wells relative to capacity by a factor of five. Playa del Rey has the most total monitoring and remediation wells relative to capacity by a factor of two. Lodi Gas has the most groundwater wells relative to capacity, with Playa del Rey, Pleasant Creek Gas, and Princeton Gas following.

Table 1.1-13 lists the maximum perforation depths for each groundwater well type in each facility. The maximum perforation depth is shown rather than an average or other statistical measures, because the maximum depth provides the best measure of water that can potentially be utilized, and for many well types in many facilities, there are in any event too few data available to justify use of other statistical measures.

Table 1.1-13. Maximum perforation depth (ft) in each well type in each facility (bottom of perforation interval (BPI)) (DWR, 2017). The maximum and estimated numbers of wells from Table 1.1-11 are repeated in this table for ease of comparison. The shading of these numbers is the same as in Table 1.1-11. BPI availability for less than a quarter of wells are highlighted in pink, from a quarter to less than half in orange, and from a half to less than three quarters in yellow. See Table 1.1-11 for footnotes and caption for more details.

Facility		Independents					PG&E			SoCalGas			
		Gill Ranch Gas	Kirby Hill Gas	Lodi Gas	Princeton Gas	Wild Goose Gas	Los Medanos Gas	McDonald Island Gas	Pleasant Creek Gas	Aliso Canyon	Honor Rancho	La Goleta Gas	Playa del Rey
Unknown	Est. #	4	14	8	1		8	33	1			2	1
	Max. #	4	18	15	1		9	33	2			13	1
	BPI #	2	2	0	0		3	0	0			8	1
	% with BPI	50%	11%	0%	0%		33%	0%	0%			62%	100%
	Max. BPI depth (ft)	803	7				426					312	45
Public supply	Est. #			0			1	3	1		0	1	
	Max. #			1			1	3	1		1	5	
	BPI #			0			0	2	1		1	5	
	% with BPI			0%			0%	67%	100%		100%	100%	
	Max. BPI depth (ft)							120	100		135	1270	
Domestic	Est. #	2	2	157	10	1	9	10	4		1	8	
	Max. #	2	8	268	12	2	11	12	6		4	31	
	BPI #	2	5	136	2	0	8	7	5		4	30	
	% with BPI	100%	63%	51%	17%	0%	73%	58%	83%		100%	97%	
	Max. BPI depth (ft)	240	195	480	250		320	290	279		145	482	
Industrial[1]	Est. #				2		2					5	
	Max. #				2		2					11	
	BPI #				1		2					10	
	% with BPI				50%		100%					91%	
	Max. BPI depth (ft)				270		120					505	

Facility		Independents					PG&E			SoCalGas			
		Gill Ranch Gas	Kirby Hill Gas	Lodi Gas	Princeton Gas	Wild Goose Gas	Los Medanos Gas	McDonald Island Gas	Pleasant Creek Gas	Aliso Canyon	Honor Rancho	La Goleta Gas	Playa del Rey
Remediation[2]	Est. #				8							3	
	Max. #				8							48	
	BPI #				0							48	
	% with BPI				0%							100%	
	Max. BPI depth (ft)											26	
Irrigation	Est. #	20	1	32	14	0	1	0	7		1	2	
	Max. #	20	1	59	19	1	1	1	11		3	4	
	BPI #	20	0	17	11	0	1	0	11		1	3	
	% with BPI	100%	0%	29%	58%	0%	100%	0%	100%		33%	75%	
	Max. BPI depth (ft)	510		693	400		200		870		136	440	
Monitoring, piezometer, temporary	Est. #	3	1		1	1	6	42		2	4	33	7
	Max. #	3	1		1	1	6	44		3	8	94	19
	BPI #	3	1		1	1	4	3		3	8	83	13
	% with BPI	100%	100%		100%	100%	67%	7%		100%	100%	88%	68%
	Max. BPI depth (ft)	50	16		285	540	24	16		240	50	100	113
Instrument[3]	Est. #		1				4			2	2	4	4
	Max. #		1				4			2	2	4	4
	BPI #		1				2			2	3	1	3
	% with BPI		100%				50%			100%	150%	25%	75%
	Max. BPI depth (ft)		250				250			500	500	360	400

For well type-facility combinations with ten or more wells, a review of maximum perforation depth histograms indicates that the distribution of these depths is long-tailed (left-skewed). In only one case, though, is the deepest perforation depth in a well population more than 300 ft deeper than the next deepest perforation depth in that population. This occurred at the La Goleta facility. As shown by Table 1.1-14, this facility is not in a groundwater basin. This is apparently because of its proximity to the coast and associated saltwater intrusion based on the limits of the groundwater basin located just inland. The deep well, which is for public supply, is located toward the inland edge of the facility.

Table 1.1-14. Basin, sub-basin, and basin prioritization for implementation of the Sustainable Groundwater Management Act at each facility.

Facility	Bulletin 118 - 2016 update (DWR, 2016)		Prioritization[1]
	Basin	Sub-basin	
Gill Ranch Gas	San Joaquin Valley	Delta-Mendota	High
Kirby Hill Gas	Suisun-Fairfield Valley	Suisun-Fairfield Valley	Very low
Lodi Gas	San Joaquin Valley	Eastern San Joaquin Valley	High
Princeton Gas	Sacramento Valley	Colusa	Medium
Wild Goose Gas	Sacramento Valley	East Butte	Medium
Los Medanos Gas	None		
McDonald Island Gas	San Joaquin Valley	Tracy	Medium
Pleasant Creek Gas	Sacramento Valley	Yolo	High
Aliso Canyon	None and San Fernando Valley	None and San Fernando Valley	Medium
Honor Rancho	Santa Clara River Valley	Santa Clara River Valley East	Medium
La Goleta Gas	None		
Playa del Rey	Coastal Plain of Los Angeles	Santa Monica and West Coast	Medium

1 From CASGEM Groundwater Basin Prioritization Results – Abridged Sorted by Overall Basin Score," version 05262014, available at http://www.water.ca.gov/groundwater/casgem/pdfs/lists/StatewidePriority_Abridged_05262014.xlsx

A few of the facilities are located in high-priority basins with regard to implementation of the Sustainable Groundwater Management Act, as shown in Table 1.1-14. Most of the remaining facilities are located in medium priority basins.

Table 1.1-15 provides various depths relevant to the extent of and risk to fresh groundwater and potential underground sources of drinking water (groundwater with <10,000 mg/L total dissolved solids (TDS), although other factors, like the presence of minerals, can exclude waters that meet the TDS criterion). As shown, in some facilities, gas storage occurs above the base of fresh groundwater, while in others it occurs a short distance below. Any leakage from these facilities via geologic pathways through the caprock is likely to impact fresh groundwater. The table also lists the percentage of the fresh groundwater thickness that has groundwater wells. This provides some indication of the opportunity to replace groundwater impacted by a leak, such as from a storage well, with groundwater from another zone in the section.

Table 1.1-15. Depth of water table, base of fresh water (BFW), various total dissolved solids (TDS) concentrations, and various other depths regarding gas storage and groundwater well perforations. Storage within fresh water highlighted in pink, storage less than 1,000 ft deeper than freshwater in orange, and between 1,000 and 2,000 ft in yellow.

Field	**Fall 2015 water table (ft)[1]**		**BFW (ft)[2]**		**TDS (mg/L; ft)**			**Min. average storage pool (ft)**	**Min. average storage pool less max. BFW (ft)**	**Max. perf. depth of public, domestic, or irrigation well**	
	Min.	**Max.**	**Min.**	**Max.**	**~2,000**	**<10,000[3]**	**>10,000[3]**			**(ft)**	**% of max. fresh water**
Gill Ranch Gas	60	140	650	950	600[4]			5,850	4,900	510	51%
Kirby Hill Gas	Not available		250	1,850		5,425		1,550	-300	195	11%
Lodi Gas	130	180	1,700	2,485		2,515		2,280	-205	693	24%
Princeton Gas	0	20	1,375	1,870				2,170	300	400	21%
Wild Goose Gas	20	20	1,000				2,500	2,400	1,400	Perf. depths not available	
Los Medanos Gas	Not available		835	2,140			4,000	4,000	1,860	320	15%
McDonald Island Gas	Not available		50	100			5,220	5,220	5,120	290	290%
Pleasant Creek Gas	80	110	1,150	2,270				2,800	530	870	36%
Aliso Canyon	Not available		Not available			4,150	5,179	9,000	BFW not available	No wells	
Honor Rancho	Not available		Not available				10,000	10,000	BFW not available	145	BFW not available
La Goleta Gas	Not available		No fresh water			3,950		3,950	3,950	1,270	No freshwater
Playa del Rey	Not available		700		800[6]		6,200	6,200	5,400	No wells	

1 2016011_011439 version of measurements and contours downloaded from https://gis.water.ca.gov/app/gicima/

2 As listed in DOGGR's field rules for each field available at http://www.conservation.ca.gov/dog/field_rules on August 18, 2017

3 As listed in DOG (1982; 1992), and DOGGR (1998)

4 Page (1973)

5 Berkstresser (1973)

6 DWR, Southern District (1961)

1.1.9 Findings, Conclusions, and Recommendations

Data Quality in DOGGR's Public Datasets

Finding: Information regarding quality control for public datasets relevant to underground gas storage is not available. Aspects of the data suggest quality control processes are not uniformly applied. For instance, well API# 03700722 has high casing and zero tubing pressures at times when its configuration suggests this is not possible. It also has the same casing pressure reported to four significant figures monthly from August 2008 through April 2009. While there appears to be sufficient consistency within the data to provide for accurate characterization of gas storage across the state, the narrower the focus, such as upon a single well, the less accurate the data can be presumed. This can interfere with understanding the risk of events at particular wells and other facilities of interest. As another example of data inconsistencies, some data regarding the same feature varies between publicly available datasets. For instance, well API #03714015 is in the Del Rey Hills area of the Playa del Rey field, which has gas storage, in DOGGR's production and injection database, but is in the Venice area, which does not have gas storage, in DOGGR's AllWells file. The uncertainty created by such inconsistencies has various implications—for instance, whether this well accesses the gas storage reservoir or not affects the LOC risk of that storage. As with the previous finding, though, these inconsistencies do not appear to be sufficiently frequent to preclude accurate characterization of UGS in California.

Conclusion: While DOGGR's public databases provide a wealth of information on UGS wells, this study finds that there are various obvious inconsistencies between and apparent inaccuracies within these databases, which suggests that either quality control processes do not exist or are not uniformly applied. We could not find information regarding quality control for these public datasets relevant to underground gas storage. (See Conclusion 1.21 in the Summary Report.)

Recommendation: We recommend that quality control plans need to be made available if they exist, or need to be created if they do not exist. DOGGR needs to check for consistency between datasets and correct inconsistencies. In the longer-term, DOGGR should develop a unified data source from which all public data products are produced. (See Recommendation 1.21 in the Summary Report.)

Storage in depleted oil versus gas reservoirs and independent versus utility operated

Finding: Storage in depleted gas reservoirs (primarily in northern California) differs from storage in depleted oil reservoirs (only in southern California) in a variety of ways, including:

- Well age and orientation
- Wellhead distribution
- Reservoir depth, initial pressure, and temperature

- Reservoir operating pressure relative to initial pressure
- Compounds in produced gas

Storage by independent operators differs from storage by PG&E, both in depleted gas reservoirs, in a variety of ways, including:

- Well age
- Interconnect length per capacity and gas transferred
- Location of gas handling plant relative to wells

Conclusion: The systematic physical and operational differences between storage in depleted oil and gas reservoirs, and independent versus utility operated in depleted gas reservoirs as practiced, may result in significantly different risk profiles between these types of storage fields.

Recommendation: Characterize gas storage risk in depleted oil versus gas reservoirs, and independent versus utility operated in depleted gas reservoirs, to determine if there are generic differences, such as by simulating well blowouts for each. Identification of such differences might lead to different mitigation approaches in each setting, and identify practices that could be transferred between settings.

<u>Storage wells in southern California</u>

Finding: Almost two thirds of the wells used for storage in southern California were spudded six to nine decades ago. Two fifths of stored gas was transferred via these wells.

Conclusion: There does not appear to be any limit on the age of well components used for gas storage in the state.

Recommendation: Determine the reasonable life expectancy of a well component given its operation and maintenance, and determine a monitoring and testing schedule that varies based on the temporal failure rate distribution of that type of component.

1.2 FAILURE MODES, LIKELIHOOD, AND CONSEQUENCES

1.2.1 Abstract

We review the main failure modes, likelihood of failure, and the consequences of failure of UGS in California. For the purposes of this section, failure is most commonly loss-of-containment (LOC), but it can also be damage to a well or other component that affects health and safety, the environment, or facility operations without LOC. The reason LOC is the main focus is that UGS involves containing through multiple repeated operations (compression, injection, storage, withdrawal, decompression, processing, utilization) of a highly flammable gas at very high pressure. In the subsurface part of UGS, well integrity and reservoir integrity are needed to contain natural gas. Well integrity failures can occur for many reasons, but failure of cement seals and corrosion of casing are two of the main causes of subsurface LOC. Reservoir integrity relies on caprock sealing and lack of transmissive faults, both of which have been known to fail at UGS systems in the past. In the surface part of UGS, failure can occur by damage to pipelines, valves, seals, and many other components relied upon to contain high-pressure gas in the aboveground infrastructure of UGS facilities. Some California UGS facilities identified here are located in regions with particular hazards, among which are seismic, landslide, flood, tsunami, and wildfire hazards, all of which are external events that can affect UGS infrastructure. Human and organizational factors are widely cited as a cause of incidents at industrial facilities such as UGS sites.

The likelihood of UGS facility failure can be qualitatively estimated by the record of reported incidents in California. This record suggests that an incident of severity significant enough to have been reported will occur on average 4.1 times per year somewhere in California, and most of these incidents will be caused by well integrity failures. But these statistics must be used cautiously, because the overall number of events is relatively small, and reporting of incidents has not been regulated or standardized. The consequences of LOC incidents can be catastrophic, as in the case of large releases such as occur during well blowouts or flowline rupture with ignition, or they can occur without impacts to safety but with potential long-term impact to environment, as in the case of chronic low-flow-rate leakage of methane in the context of its role as a greenhouse gas. Dispersion of any emitted gas will occur by air entrainment and surface winds. The dispersion of leaked natural gas and resulting downwind concentrations relevant to ignition and explosivity can be modeled very accurately, provided local wind and leakage flow rate data are available. Analysis of dispersion of leaked natural gas suggests that the footprint of methane concentrations between the lower and upper flammability limits can be expected to exceed the size of the clustered surface infrastructure (e.g., a compressor pad, gas-processing facility pad, or the clustered wellheads on pads of multiple deviated wells) for large but not impossible leakage fluxes, meaning that the surface infrastructure is vulnerable to explosion hazard. Subsurface leakage of natural gas, e.g., by annular overpressurization, can allow natural gas to flow into underground sources of drinking water (USDW), typically at much shallower levels than the storage reservoir. There are recorded incidents of natural gas leaking to surface that must have encountered USDW, although specifics of the impacts have not been

assessed to our knowledge. In general,
we believe adherence to the new regulations proposed by California Division of Oil, Gas and Geothermal Resources (DOGGR) will strongly reduce the likelihood of well integrity failures.

1.2.2 Introduction

This section reviews the failure modes, likelihood of failure, and the consequences of failure of UGS in California. Using a combination of literature review of UGS worldwide, and knowledge of California's specific UGS system characteristics as reviewed in Section 1.1, we can develop an understanding of the potential impacts of UGS in California and their likelihood. We do not carry out a formal risk assessment for any site or any risk category. Instead, we discuss the likelihood and consequences of LOC and other kinds of incidents. Actual health and safety hazards arising from the various failure scenarios are discussed in Section 1.4. In this section, we will do the following:

1. Discuss the ways that UGS components and systems most commonly fail
2. Describe the interactions between components in failure scenarios
3. Review the estimation of UGS failure likelihood in California
4. Review the consequences of UGS failure scenarios in terms of dispersion patterns
5. Review the impacts of failures on the UGS infrastructure (e.g., fire and explosion)
6. Review impacts of failures on resources such as USDW

1.2.3 Failure Modes

1.2.3.1 Introduction

There are three fundamental types of UGS failure: (1) facility cannot accept gas from the transmission pipeline for injection; (2) facility cannot deliver high-quality gas back to the pipeline; or (3) facility fails to contain gas. There are many different causes for these three potential failure types. For example, inoperable or malfunctioning equipment, including flowlines, may prevent the facility from receiving gas from the pipeline. Similarly, malfunctioning gas processing equipment may prevent the facility from delivering high-quality gas back to the transmission pipeline. Moreover, the well or the formation may be damaged and not functioning as required for gas injection and/or production. Failure Types 1 and 2 do not necessarily involve a hazard to health, safety, and the environment (HSE). On the other hand, Type 3, loss-of-containment (LOC), involves potentially catastrophic consequences for human health (including loss of life), UGS infrastructure, environmental resources, and surrounding property. In this section, we focus on Type 3 failures and LOC risk, because it is the largest hazard to HSE and UGS infrastructure. The Type 3 failure can occur by a wide variety of modes, as will be described below.

Prior studies have lumped UGS failures into a single category referred to as *incidents* (Evans, 2009; Folga et al., 2016; Schultz et al., 2017). Folga et al. (2016) use the term *incident* to refer to a broad array of operational dysfunctions, many of which do not shut down the whole facility. The term *incident* is preferable to *accident*, because it is more general and does not imply anything about intent or cause. Some authors add the term *major* (or *severe* or *significant*) as a modifier to the term *incident* (International Energy Agency Greenhouse Gas (IEAGHG), 2006; Folga et al., 2016) and define major incidents as those involving injury/fatality, property damage, site evacuation, or uncontrolled leak, although no thresholds for injury, property damage, or leakage rate are provided. Recently, Evans and Schultz (2017) have introduced the term *occurrence* in place of *incident* to acknowledge that many reports of dysfunction are very minor and do not result in LOC or facility interruption. Evans and Schultz (2017) have also introduced a severity ranking for occurrences. The field of UGS dysfunction cataloging, data analysis, and severity ranking is dynamic at present, and no single agreed-upon terms or severity thresholds have emerged.

Here we use the term *incident* to refer to reported events related to loss-of-containment of natural gas of any magnitude arising for any reason or underlying cause. For example, loss-of-containment could occur from leaks in flowlines, valves, compressors, gas-processing units, wellheads, wells, caprock, and faults. The results of such incidents may be injury or death, e.g., from resulting fires and explosions, or damage to the facility or other property, not to mention loss of stored gas and potential related environmental damage. Because minor incidents are not reported and cataloged for evaluation, we normally use the term *incident* without a modifier. By this usage, the term *incident* will implicitly refer to events related to significant loss-of-containment of stored gas, i.e., significant enough that it warranted reporting.

The term *leakage* also requires definition. As used here, the term *leakage* refers to flow or migration of gas out of the storage system, which includes the surface infrastructure designed to contain the high-pressure gas along with the well and the subsurface reservoir. By this definition, leakage may involve deep casing failures and/or migration of gas out of the reservoir but not necessarily into the atmosphere. This definition follows prior use of the term *leakage* in the area of geologic carbon sequestration (e.g., Oldenburg et al., 2009), in which field leakage to atmosphere is called *surface leakage*.

The term *loss-of-containment (LOC)* is defined here as the unplanned release of stored gas or related fluid into the environment, subsurface or aboveground. As such, the terms leakage and *LOC* are synonymous; there may or may not be loss to atmosphere depending on where the leakage occurs.

1.2.3.2 Origin of High Pressure in UGS

Water wells, along with most oil wells, differ fundamentally from gas wells with respect to the pressure along the length of the well and at the wellhead. Specifically, water wells and oil wells usually need a pump to produce fluid from the well, whereas natural gas flows freely and rapidly if not contained at the wellhead. The reason for this difference is shown by the pressure profiles presented in Figure 1.2-1 (after Smit et al. (2014), Figure 9.6.3). Figure 1.2-1 depicts the relevant profiles of pressure in the subsurface along with a representative gas well accessing a gas reservoir at 2 km (~6,600 ft) depth that is at hydrostatic pressure. As shown, the gas-static pressure in the well does not vary significantly along the length of the well, because methane density averages only about 70 kg/m^3 in the well (at P = 10 MPa (1,450 psi) and 45°C (113°F) at depth of 1 km), which is small relative to water density, which is about 14 times larger. As shown, the gas pressure in the well is higher than the hydrostatic pressure everywhere above the reservoir, and it is higher than the frac gradient (or fracture gradient) and lithostatic pressure above about 500 m (1,600 ft) depth in the well. Therefore, in order to contain the gas in the subsurface and surface systems, the wells and surface infrastructure connected to the wells must be capable of holding this large pressure (~20 MPa = ~2900 psi) relative to the formation pressure at any depth and relative to atmospheric pressure in aboveground infrastructure. In addition, pressure in the well may be even higher during injection.

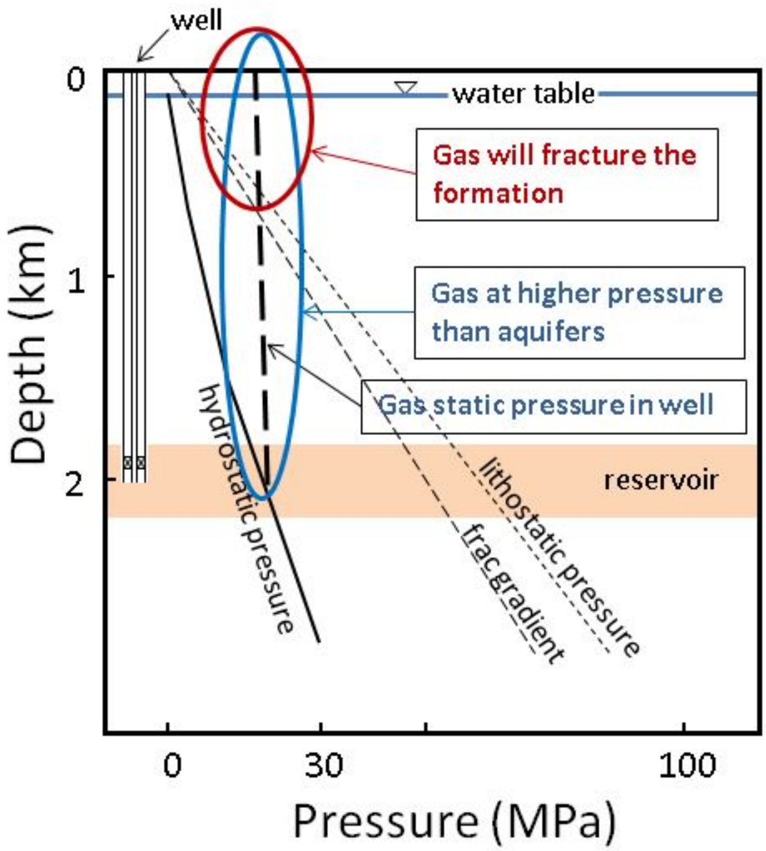


Figure 1.2-1. Sketch of pressure profiles as a function of depth showing that a well filled with natural gas and held at hydrostatic pressure in the gas reservoir must be able to withstand and contain pressure throughout its length as indicated by the gas static pressure profile. The figure shows that in the shallow parts of the well (less than depths of ~500 m shown by red circle), gas pressure may exceed the fracture gradient and lithostatic pressure meaning LOC can fracture the formation. Throughout the length of the well, the gas pressure is higher than hydrostatic pressure (blue circle) meaning LOC can lead to gas entering aquifers.

1.2.3.3 Wells Couple Surface and Subsurface Parts of UGS

Coupling the surface (engineered) and subsurface (wells plus geologic storage system) parts of the UGS system (see Figure 1.0-1) is challenging and creates potential vulnerabilities to storage integrity. These challenges arise from the heterogeneity and incomplete knowledge inherent in subsurface systems. The main component involved in coupling the engineered and natural systems is the well, which consists of multiple steel casings and (normally) tubing that allows injection and withdrawal of gas and liquids. A primary component of a well in a gas storage reservoir is the cement that seals the gaps between the outermost well casing and the rock comprising the sides of the wellbore.

It is notable that UGS wells in California and elsewhere in the U.S. as a rule carry out production and injection not only through tubing, as in nearly all other injection and production wells (e.g., in oil and gas, and in deep disposal operations), but also through the casing, or so-called A-annulus. This aberration in standard practice is allowed in the UGS industry because UGS is excluded from the U.S. EPA's Underground Injection Control (UIC) program, which requires tubing and packer (no A-annulus injection or production). The UIC program arose from the Safe Drinking Water Act (SDWA), which authorizes the U.S. EPA to oversee states, municipalities, and water suppliers in maintaining standards for drinking water quality. In addition, the SDWA establishes requirements and provisions for regulation of fluid injection into the subsurface. The U.S. EPA administers the UIC program to regulate subsurface fluid injection. Most fluid injected underground consists of oil-production-related wastewater, but a wide variety of fluid-injection operations are regulated under the UIC (Clark and Veil, 2009). Notably, injection wells involving any hydrocarbon substance that is a gas at standard conditions of 1 bar and 15°C (0.987 atm, 60°F) are exempted from UIC. Methane clearly falls into this category, which leads to the fact that UGS wells in the U.S. are not regulated under UIC and therefore UGS wells are not required to have barriers conforming to the two-point failure standard (see Figure 1.2-2 and related discussion below).

We note in passing that CO_2 is also a gas at standard pressure and temperature, but it is not a hydrocarbon, and therefore geologic carbon sequestration wells are regulated by the U.S. EPA under the UIC program (U.S. EPA, 2012; IEAGHG, 2006).

We present in Figure 1.2-2 a sketch of a UGS well based loosely on the Standard-Sesnon-25 (SS-25) well at Aliso Canyon that sustained a blowout in 2015 (e.g., Interagency Task Force on Natural Gas Storage Safety, 2016, p. 18 ff). As shown, the well is constructed using an 11 ¾-in surface casing cemented to ~1,000 ft, surrounding a 7-in production casing that extends to the reservoir. Cement also is present from the reservoir extending through the caprock. The purpose of the cement along the outside of the casing through the caprock is to seal the reservoir from formations above along the well. As discussed above, the cement seal through the caprock must be able to withstand the large pressures developed in the reservoir. Often (particularly in older wells), the cement sealing the well through the caprock does not extend to surface, leaving several thousand feet of uncemented casing. The gap outside of casing in this case may be filled with formation water or drilling mud. Regardless, this gap cannot be considered a barrier for gas containment and can act instead like a leakage pathway.

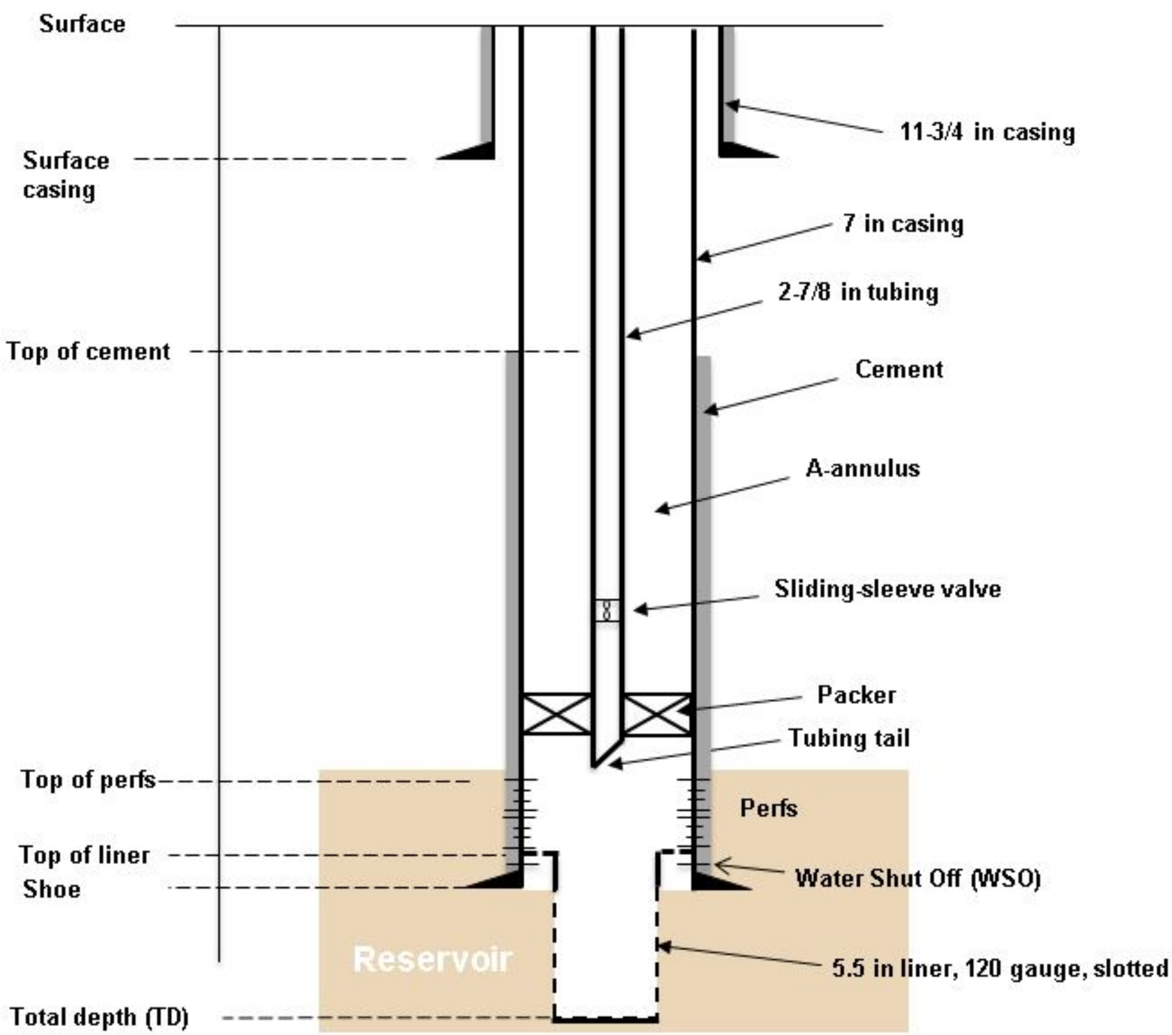


Figure 1.2-2. Simplified sketch (not to scale) of a UGS well based loosely on the Aliso Canyon SS-25 well. Perfs (short for perforations) are the holes or slots that serve to connect the well to the reservoir fluids.

Although the well depicted in Figure 1.2-2 has a tubing and packer, the tubing in this well is connected to the A-annulus by open ports. In the case of the SS-25 well, these ports were the remnants of a dismantled sliding sleeve valve. California UGS wells commonly utilize the A-annulus for production in order to maximize deliverability, i.e., the entire A-annulus is used as a flow zone for production and injection. As shown in Section 1.1, Figure 1.1-10, nearly every UGS well in California has equal pressure in the tubing and A-annulus, indicating the two parts of the well are connected, resulting in high pressure in the A-annulus.

The use of the A-annulus for injection and production has been standard practice in UGS, even though it allows high-pressure gas to contact the casing along the entire length of the well, including regions of the well with no cement outside of casing. This configuration allows additional strain on the casing, because there is only water or mud in the gap between casing and rock to counteract the high-pressure gas inside the casing. Overall, the connection of tubing to A-annulus, and/or use of the A-annulus for gas production and injection, creates a configuration that allows for what is referred to as a single-point failure, because any failure of the casing integrity can lead to high-pressure gas leakage. Normally, oil and gas wells and injection wells regulated under UIC are not constructed nor configured to operate in this way. Instead, normal oil and gas wells and injection wells only inject or produce high-pressure fluids through the tubing, reserving the A-annulus to serve as a secondary volume available for monitoring uses that is confined by the casing, which serves as the secondary barrier in case the packer or tubing fail. This standard injection and production well configuration, used throughout the oil and gas and the deep-fluid injection industry, as regulated by UIC, creates a two-point failure configuration. In other words, in order for the well to suffer LOC (lose integrity) by tubing, packer, or casing failure, more than one of these components would have to fail at the same time. Two-point failure configurations are much safer than single-point failure configurations. The exclusion of UGS from UIC as discussed above allows reliance on single-point failure configurations (e.g., Michanowicz et al., 2017). Under the emergency regulations imposed by DOGGR on January 15, 2016, single-point failure configurations were effectively outlawed. Additional permanent UGS regulations currently under consideration will take effect January 1, 2018 (see Section 1.6).

1.2.3.4 Loss-of-containment from the Subsurface System

Stripped to the essentials, well integrity relies on cement, steel, and pressure control, e.g., through use of heavy drilling mud and kill fluids during drilling and other well work-over operations. The purpose of gas wells in the context of this study is to convey fluids to and from the reservoir without allowing (a) gas from the reservoir to leak out anywhere along the length of the well, and (b) to prevent fluids from intermediate levels along the length of the well from flowing up or down along the well. Well construction is carried out to achieve these goals through the use of (multiple) steel casings and cement that bonds to the steel and/or the borehole wall to form a seal that resists high-pressure fluids from flowing past or through the sealed intervals. In abandoned wells, a cement plug may be used in the production casing to block off potential flow in the well.

We present in Figure 1.2-3 the iconic figure for well integrity introduced in the field of geologic carbon sequestration (Gasda et al., 2004) but very useful in the gas storage context also. As shown, multiple barriers are commonly employed in wells to contain high-pressure fluids. Nevertheless, sealing wells is challenging because of access limitations, the heterogeneous properties of subsurface formation, and extreme conditions of temperature, pressure, and fluids (e.g., acid gases creating corrosive environments). As shown in Figure 1.2-3, a host of failure modes for well seals is recognized.

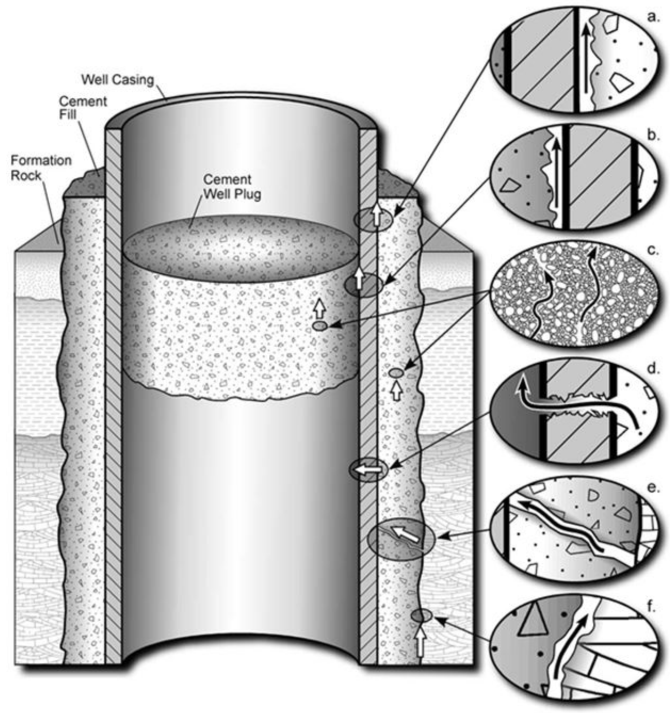


Figure 1.2-3. Three-dimensional cross section of a generic well (in this case shown with a cement plug for discussion purposes) showing production casing, cement, and formation along with various failure modes (a) bad seal between casing and cement; (b) bad seal between cement plug and casing; (c) leakage through the cement pore space as a result of cement degradation; (d) leakage through casing as a result of corrosion; (e) leakage through fractures in cement; and (f) leakage between cement and rock. From Gasda et al. (2004) (drawing by Dan Magee, Alberta Geol. Survey).

In addition to subsurface sealing capability, well integrity also relies on protection of the wellhead, e.g., from impacts such as those from vehicles or other heavy equipment. The wellhead forms the intersection of the surface and subsurface systems of UGS as shown in Figure 1.0-1. Looked at in more detail, well integrity vulnerability can be divided into surface threats and subsurface threats.

We present in Figure 1.2-4 a list of the numerous modes by which UGS wells can fail. This list was developed from the authors' experience with well integrity, along with review of multiple documents including API 1171 (API, 2015), the States First report (GWPC and IOGCC, 2017), Miyazaki (2009), and Michanowicz et al. (2017). As shown, the main well integrity issues can be divided into surface, casing or liner, tubing, and abandonment categories. Numerous components, events, and processes can lead to failure to contain fluid in the well. A great deal of information is contained in the list that is useful to understand well vulnerabilities and which can therefore be used to suggest corresponding monitoring and mitigation targets.

Well Integrity Issues:

- Surface Issues
  - Wellhead leakage
    - Valve leak
    - Fitting leak
    - Leaking around slips
    - Sand erosion
  - Third-party damage
    - Surface encroachment
    - Intentional/Unintentional damage
  - Seismic activity or other natural causes
- Casing or liner leaks
  - Internal corrosion
  - Annular fluid and gas issues
  - External corrosion – uncemented casing, flow zones, corrosion zones, other hydrocarbon zones, lost circulation zones
  - Casing shoe (seat)/formation integrity
  - Collar leaks
  - Cement integrity
    - Cement bond – pipe to formation
    - Microannulus
    - Channeled cement
    - Cement quality
  - Casing injection (packerless completion)
  - Gas production through gas mandrels (gas production through both the casing and tubing)
  - Uncemented liners
- Tubing leaks
  - Collar and thread leaks
  - Internal corrosion
  - Packer leaks
  - Annular fluid issues
- Plugging and abandonment leakage
  - Mechanical plug integrity
  - Cement plug integrity
  - Mud plug integrity
  - Temporary abandonment

Figure 1.2-4. Well Integrity Issues

Similar to the above list, we present in Figure 1.2-5 a list of the numerous ways by which loss-of-containment can occur due to failure of the geological part of a gas storage system (e.g., IPCC, 2005). We note that well integrity considerations appear in both the well and reservoir integrity lists (Figures 1.2-4 and 1.2-5), not only because of the reliance on the individual injection or production well to contain gas, but also for the reliance on surrounding wells to be sealing (outside of casing, i.e., against the formation) and not providing leakage pathways through the caprock. With this in mind, we present in Figure 1.2-6 a figure that further delineates failure modes in the well that can occur from external or internal changes in the engineered sealing capacity of the well (All Consulting, 2017; GWPC and IOGCC, 2017).

Reservoir Integrity Issues:

- Failure of the caprock/confining zone integrity
  - Overpressurization
  - Faults and fractures
  - Geomechanical stresses
- Geologic seal confinement – structural and stratigraphic traps
  - Anticlines
  - Pinch-outs
  - Facies changes
  - Faulting – frictional stability in a compartmentalized reservoir
    - Transmissive
    - Non-transmissive
  - Structural spill points and overfilling
  - Geological uncertainty – extent of reservoir boundary
    - Expansion, contraction, and migration of storage gas
    - Availability of pathways for migration
- Damage to the reservoir
  - Seismic activity
  - Contamination by foreign fluids
  - Storage formation damage
- Artificial penetrations – Breaches of vertical and horizontal containment
  - Third-party damage (drilling, completion, workover, and plugging activities)
  - Gas storage wells
  - Oil and gas production wells
  - Enhanced recovery and disposal wells
  - Plugged wells
  - Abandoned or improperly plugged wells
  - Temporarily abandoned wells
  - Monitoring or observation wells

Figure 1.2-5. Reservoir Integrity Issues.

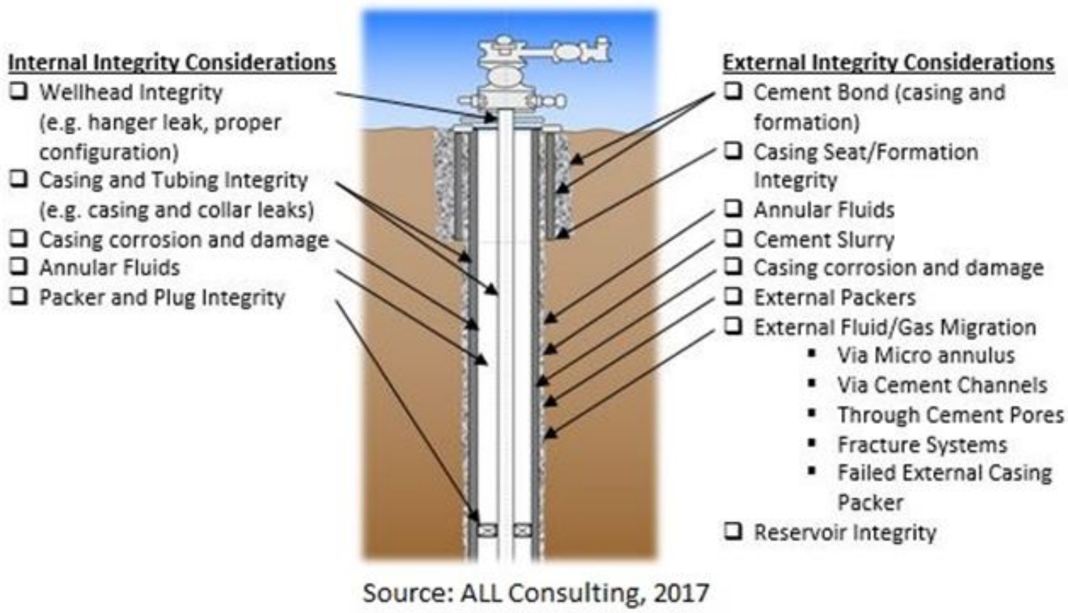


Figure 1.2-6. Well diagram showing internal and external integrity considerations (ALL Consulting, LLC, 2017).

1.2.3.5 Loss-of-containment from Surface System

A representative set of surface components of UGS systems in California is shown in Figure 1.0-1 up- or downstream of the wellhead, depending on whether injection or production are occurring, respectively. Although only a handful of representative components are depicted in Figure 1.0-1, the term *component* has been defined in new California Air Resources Board (CARB) regulations as any valve, fitting, flange, threaded-connection, process drain, stuffing box, pressure-vacuum valve, pressure-relief device, pipes, seal fluid system, diaphragm, hatch, sight-glass, meter, open-ended line, well casing, natural gas powered pneumatic device, natural gas powered pneumatic pump, or reciprocating compressor rod packing or seal (California Code of Regulations, 2017).

There are many failure modes applicable to surface UGS components, which are in fact the same components in wide use throughout industrial facilities such as oil and gas fields, oil refineries, chemical plants, factories, food processing plants, and power plants in California. A listing of the threats to gas pipelines has been outlined in the ASME B31.8S report on managing of system integrity of gas pipelines (ASME, 2016). We present in Figure 1.2-7 these threats in three categories (time-dependent, stable, and time-independent). As shown, time-dependent processes include corrosion, which is not confined to pipelines but rather can occur in any other steel component if not controlled and mitigated. Then there are so-called stable threats, which implies that the pipeline (or component) has an inherent flaw or defect that does not necessarily worsen (or improve) with time. Finally, there are time-independent threats that can encompass the kinds of threats that persist over time, such as the potential for impacts to the pipeline (or component) including third-party impacts, vandalism, human error, and the natural hazards inherent to facility siting such as floods, landslides, wildfires, and earthquakes.

Failure modes common to surface piping, valves, compressors, etc. that are listed in Figure 1.2-7 to the left of “incorrect operational procedure” are continuously addressed through better inspection, engineering, manufacturing, security, and materials use. In fact, the surface components of UGS in California are mostly off-the-shelf components manufactured by reputable companies with long histories of quality control. Furthermore, surface components such as these are regularly inspected, maintained, and replaced by the facility operator or its contractors. Because there is nothing unique about UGS surface infrastructure for this subset of threats and related failure modes, we focus here on the failure modes of surface infrastructure that are unique to UGS in California, such as listed on the far-right-hand side of Figure 1.2-7.

Figure 1.2-7. Time-dependent, stable, and time-independent threats to pipelines as summarized by Dynamic Risk (Calgary) and listed in ASME B31.8S (ASME, 2016).

In particular, the concerns for UGS in California most relevant to this study are the failure modes of the surface components critical to high-pressure gas containment that are caused by the challenging environments at the UGS sites. For example, failures of surface infrastructure at various California UGS facilities can occur as a result of landslides, earthquakes, tsunamis, floods, and wildfires. The main vulnerability is to the flowlines that along or above the ground surface, and the compressors and gas turbine facilities, along with wellheads. At UGS facilities with significant topography such as Aliso Canyon, Honor Rancho, and Kirby Hills (see Section 1.1), landslide is a hazard that can lead to flowline failure through disruption of the pipe supports and corresponding buckling or shear of the pipe leading to rupture. Similarly, earthquakes can cause pipelines, buildings, and large equipment to be displaced from their supports and lead to ruptures. Finally, the La Goleta and Playa del Rey UGS facilities lie along the coast just a few feet above sea level. Tsunamis at those locations could cause inundation and water/debris impacts that could cause pipeline, surface infrastructure, and wellhead ruptures leading to loss-of-containment. Sea-level rise is also a potential long-term concern for these coastal facilities, as it is for the McDonald Island UGS facility located in the delta region. These specific hazards are discussed in more detail below.

In summary, the modes of failure of surface infrastructure at UGS facilities in California include all of the normal modes that are present in any facility with the same components, e.g., oil refineries, oil and gas fields, and any number of other factory, power plant, or chemical plant facilities. Because these common modes such as corrosion, weld failure, seal failure, etc. are not unique to gas storage, and there is widespread industry best practices and experience that lead to high reliability and low failure rate, we focus on the surface infrastructure failure modes that are unique to UGS in California. UGS operators do not have the option of locating facilities in the most optimally safe locations, but instead have to locate them where the reservoirs are. In California, this leads UGS facilities being located in a variety of physical settings, some of which are prone to landslides, earthquakes, tsunamis, flooding, and ground subsidence.

Details of these hazards at each facility as determined by various government agencies are presented below. The presence of a hazard at a facility does not necessarily imply risk at the facility due to the hazard, because the risk may be mitigated by engineering or other measures. For instance, at the McDonald Island facility, all of the plant facilities except some of the compressors are elevated on platforms, reducing the risk to operations of flooding substantially. Whether mitigation measures exist for hazards to each facility is not listed in this report. Such mitigation measures should be listed in the risk management plans for each facility, and the effectiveness of measures that are present should be quantified in those plans, as discussed in Section 1.6.

1.2.3.6 Landslide

Landslides are the common term for a wide variety of downslope mass movements as presented in Figure 1.2-8. In California, landslides are commonly caused by heavy rainfall and associated saturation of surface soils, and by seismically induced mobilization of hillslope rock and soil.

TYPE OF MOVEMENT		TYPE OF MATERIAL		
		BEDROCK	ENGINEERING SOILS	
			Predominantly coarse	Predominantly fine
FALLS		Rock fall	Debris fall	Earth fall
TOPPLES		Rock topple	Debris topple	Earth topple
SLIDES	ROTATIONAL	Rock slide	Debris slide	Earth slide
	TRANSLATIONAL			
LATERAL SPREADS		Rock spread	Debris spread	Earth spread
FLOWS		Rock flow (deep creep)	Debris flow (soil creep)	Earth flow
COMPLEX		Combination of two or more principal types of movement		

Figure 1.2-8. Abbreviated version of Varnes' (1978) classification of slope movements. (USGS, 2014).

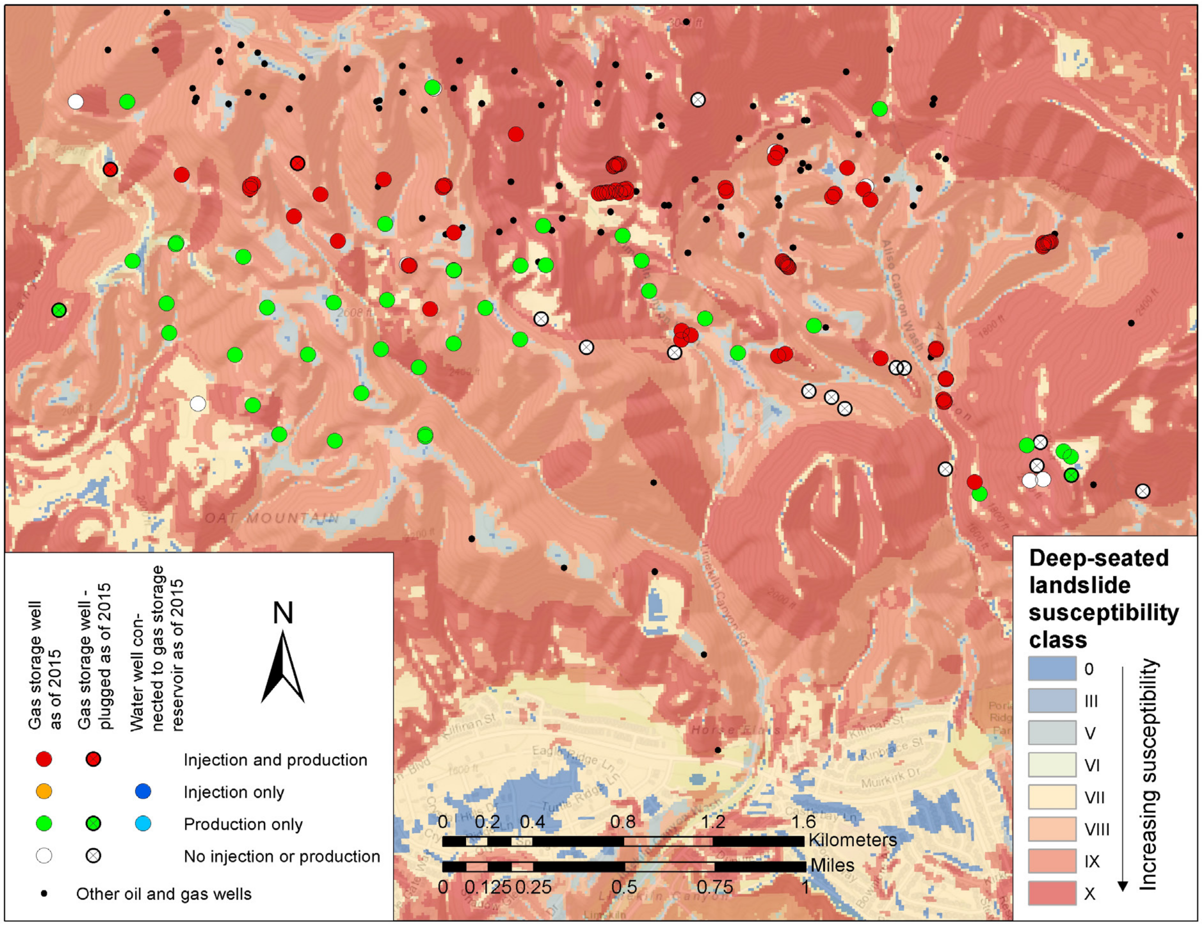
Regardless of cause, landslides are a hazard to UGS infrastructure. UGS wells can be sheared in the subsurface by movement of deep-seated (rotational and translational) landslides, and surface infrastructure can be severely impacted by landslides through (1) direct impact of soil and debris, e.g., into a flowline or wellhead, and (2) sliding or undermining of the ground beneath supports or foundations for surface infrastructure, e.g., flowlines, compressor, or gas processing foundations. In this latter case, loss of ground support could lead to collapse of a flowline or its support and subsequent rupture, bending, or compression of the line leading to failure and LOC. For compressors or other large infrastructure, loss of ground support could lead to collapse and the breaching or detachment of supply flowlines containing high-pressure gas. Loss-of-containment could result from any or all of these failure modes.

Susceptibility to deep-seated landslides in California is mapped by Wills et al. (2011) based on the assignment of land areas to one of eight classes (0, III, V, VI, VII, VIII, IX, and X) ranging from least to most susceptible. Assignments were made based on a combination of slope and rock strength. As such, the assignments do not take into account the probability of triggering events such as precipitation and earthquake shaking. Table 1.2-1 provides the predominant and maximum class (in parentheses) for each type of surface infrastructure for each UGS facility in California. The table does not include the local susceptibility to compressors or gas processing equipment (i.e., at the plant), because the susceptibility map is not meant to be used for such small locations.

Table 1.2-1. Deep-seated landslide susceptibility classes at each facility from Wills et al., 2011. Predominant class is followed by maximum class (in parentheses). Pink tint indicates classes III and V, light red tint classes VI and VII, and red classes IV and X (class XIII does not occur in table).

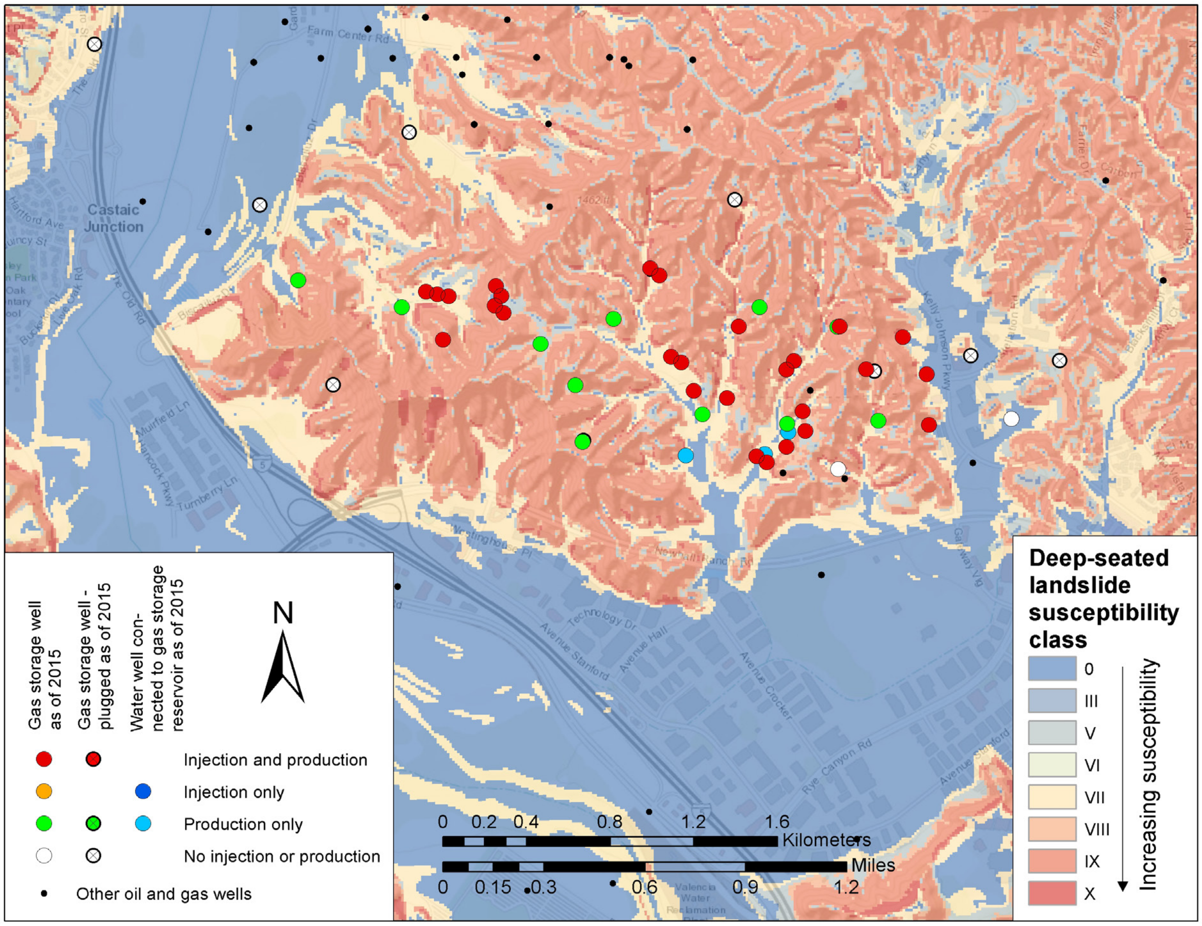
	Facility	Well(s) and flowline(s)	Interconnect
Independents	Gill Ranch Gas	0 (0)	0 (0)
	Kirby Hill Gas	0 (VI)	0 (VII)
	Lodi Gas	0 (0)	0 (0)
	Princeton Gas	0 (0)	0 (0)
	Wild Goose Gas	0 (0)	0 (0)
PG&E	Los Medanos Gas	0-III (VI)	0 (III)
	McDonald Island Gas	0 (0)	0 (0)
	Pleasant Creek Gas	0 (VII)	0 (V)
SoCalGas	Aliso Canyon	IX (X)	IX (X)
	Honor Rancho	IX (IX)	XII (X)
	La Goleta Gas	0 (X)	0 (0)
	Playa del Rey	0 (X)	0 (X)

The southern California facilities have the highest susceptibility to deep-seated landsliding, and the independently operated facilities in central and northern California have the least susceptibility as a group. Figure 1.2-9 shows the deep-seated landslide susceptibility at the southern California facilities.

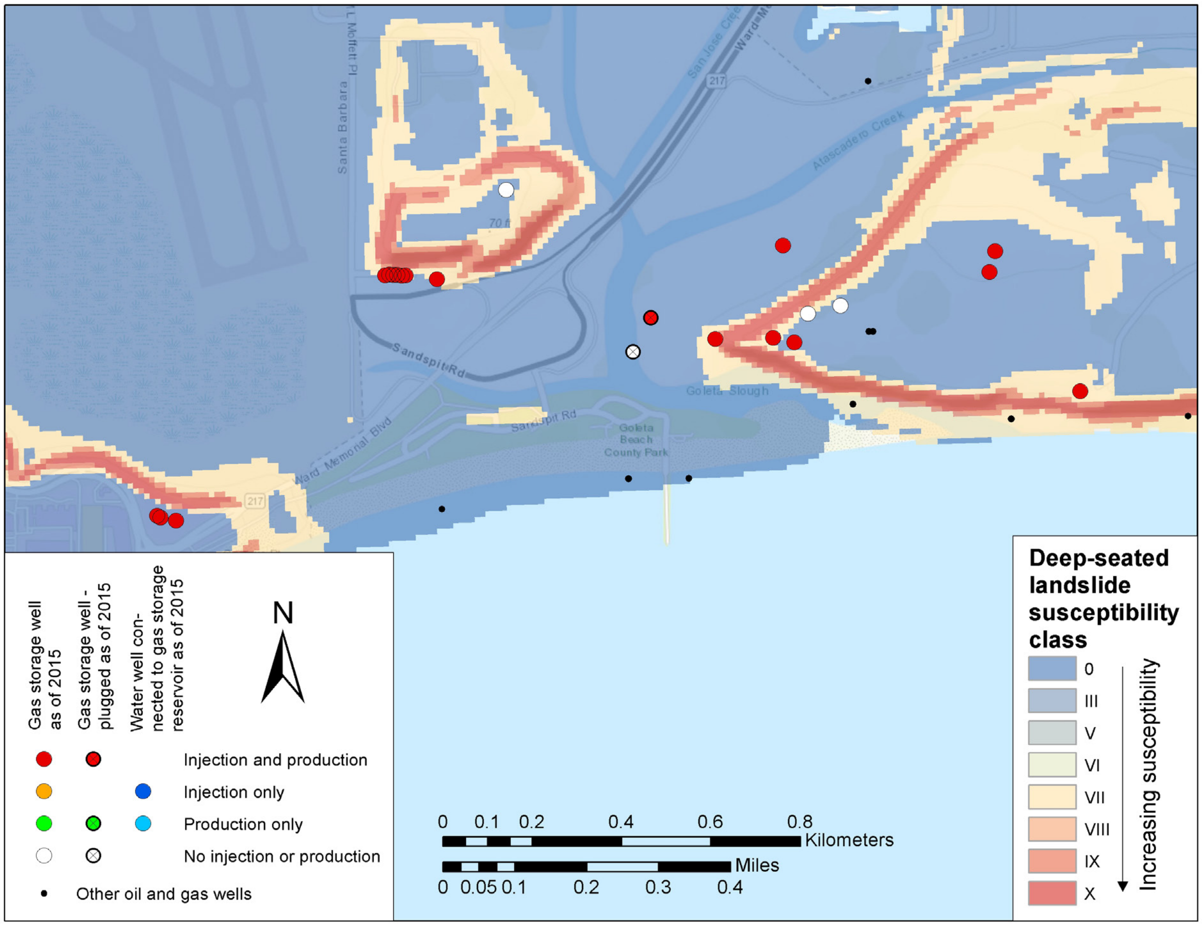


Gas storage well as of 2015
Gas storage well - plugged as of 2015
Water well connected to gas storage reservoir as of 2015
N
Injection and production
Injection only
Production only
No injection or production
Other oil and gas wells
0 0.2 0.4 0.8 1.2 1.6
Kilometers
Miles
0 0.125 0.25 0.5 0.75 1
Deep-seated landslide susceptibility class
0
III
V
VI
VII
VIII
IX
X
Increasing susceptibility
OAT MOUNTAIN

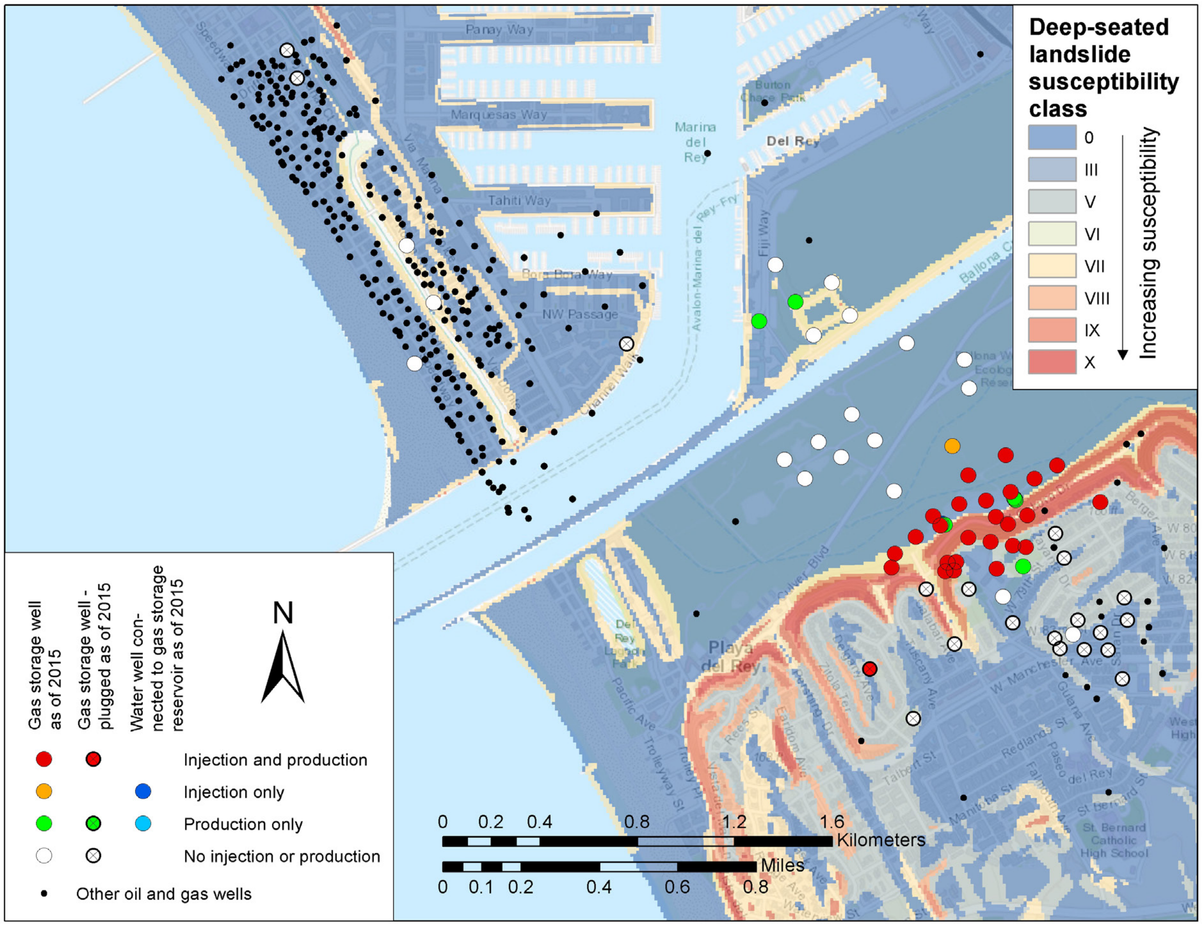
(a)


Castaic Junction
Gas storage well as of 2015
Gas storage well - plugged as of 2015
Water well connected to gas storage reservoir as of 2015
N
Injection and production
Injection only
Production only
No injection or production
Other oil and gas wells
0 0.2 0.4 0.8 1.2 1.6 Kilometers
0 0.15 0.3 0.6 0.9 1.2 Miles
Deep-seated landslide susceptibility class
0
III
V
VI
VII
VIII
IX
X
Increasing susceptibility

(b)


Santa Barbara
Sandspit Rd
Goleta Slough
Atascadero Creek
Goleta Beach County Park
Ward Memorial Blvd
217
Gas storage well as of 2015
Gas storage well - plugged as of 2015
Water well con- nected to gas storage reservoir as of 2015
N
Injection and production
Injection only
Production only
No injection or production
Other oil and gas wells
0 0.1 0.2 0.4 0.6 0.8 Kilometers
0 0.05 0.1 0.2 0.3 0.4 Miles
Deep-seated landslide susceptibility class
0
III
V
VI
VII
VIII
IX
X
Increasing susceptibility

(c)



(d)

Figure 1.2-9. Deep-seated landslide susceptibility at the southern California facilities from Wills et al. (2011) (a) Aliso Canyon, (b) Honor Rancho, (c) La Goleta, and (d) Playa del Rey.

1.2.3.7 Earthquake

The active tectonics and pervasive faulting in California mean that every UGS facility in the state is subject to some level of seismic hazard. Earthquakes can damage surface infrastructure by direct fault displacement, shaking, and ground deformation due to liquefaction and earthquake-induced landslides.

Seismic hazard analyses carried out jointly by the California Geological Survey (CGS) and the U.S. Geological Survey (USGS) to assess the potential for damaging ground shaking throughout the state consider major faults that show evidence for activity within the last 1.6 million years (the Quaternary geological period). These fault characterizations are also used for more detailed site-specific analyses of the potential for ground shaking and fault displacement. Calculation of the probabilities of these events occurring in the future—the ground shaking or fault displacement hazard—is based on the long-term rates of displacement on the faults, which are used to estimate the average time periods over which earthquakes recur. An example of seismic hazard assessment in the field of geologic carbon sequestration is given by Foxall et al. (2017). The latest ground shaking hazard assessment for California and site-specific analyses at one UGS facility currently in progress are summarized later in this section.

Fault displacement can affect surface infrastructure if fault displacement occurs in the footprint of the facility component, e.g., fault displacement through the concrete foundation of a compressor. And fault displacement can affect wells at depth through shearing of the well casing if the well crosses the plane of the fault, e.g., a dipping thrust or normal fault, on which there is slip during an earthquake or by aseismic creep.

Specifically to address surface fault displacement hazards, CGS has mapped Earthquake Fault Zones (EFZs) throughout much of the state where evidence exists for movement on a fault rupturing the ground surface during the past 11,000 years (the Holocene epoch; http://www.conservation.ca.gov/cgs/rghm/ap). Certain proposed projects, such as buildings with multiple residences, that are proposed within an EFZ must conduct a site-specific investigation to identify the location of past ground surface ruptures, if present, and set back project elements from those locations.

The location of surface infrastructure at the 12 current UGS facilities was compared to EFZ maps where they exist. All the facilities were also compared to the Quaternary Fault and Fold Database of the United States (USGS and CGS, 2006), which maps faults in California with evidence of ground surface rupture in the Quaternary period. These comparisons provide a perspective on whether an area was not mapped for EFZs because there is no fault suspected of rupturing the surface in the last 11,000 years, or because the CGS has not yet mapped EFZs in the area. It also enables an assessment of the potential for both surface and subsurface displacement on less active Quaternary faults.

As shown in Table 1.2-2, only the interconnect at Aliso Canyon is transected by the surface trace of a Holocene fault. Some wellheads in the Aliso Canyon and Honor Rancho facilities are located within an EFZ. No gas was transferred via these wells during the study period, suggesting they are used as observation wells. No flowlines to these wells are shown in the NPMS data; however, these data are missing some flowlines in both of these facilities, so such lines may exist within the EFZ at each facility. Even if such lines exist, they may not contain pressurized gas. Insofar as the wells are connected to the storage reservoir, they could be involved in an LOC incident regardless of whether or not they are currently used for production or injection. Faults listed in the vicinity of wellheads and flowlines in Table 1.2-2 are discussed further below. Faults listed as in the vicinity of interconnects are not discussed, because this hazard is not unique to UGS but rather is analogous to the far more numerous instances of faults with Quaternary rupture in the vicinity of gas pipelines throughout the state not related to storage.

Table 1.2-2. Mapped Quaternary faults at UGS facilities according to USGS and CGS (2006), and Earthquake Fault Zone (EFZ) mapping. Rows for facilities partially within an Earthquake Fault Zone are shaded red.

	Facility	Fault[1]	Last rupture (yrs ago)[1]		7.5′ quadrangle mapped for EFZs	Source
			Wellhead(s) and flowline(s)	Interconnect(s)		
Independents	Gill Ranch Gas	None			No	
	Kirby Hill Gas	Vaca	<130,000	<130,000	No	
		Kirby Hills	<130,000*			
	Lodi Gas	Unnamed		<1,600,000*	No	
	Princeton Gas	None			No	
	Wild Goose Gas	None			No	
PG&E	Los Medanos Gas	Unnamed	<130,000*		Yes[1]	1CGS (1993)
	McDonald Island Gas	None			No	
	Pleasant Creek Gas	None			No	
SoCalGas	Aliso Canyon	Santa Susana	<15,000*	<15,000	Yes[2]	2CGS (1976)
			<130,000	<130,000		
		Mission Hills		<130,000		
	Honor Rancho	San Gabriel	<15,000*		Yes[3]	3CGS (1995a,b)
			<130,000*			
		Holser	<130,000*	<130,000*		
	La Goleta Gas	More Ranch	<130,000*	<130,000*	No	
	Playa del Rey	Charnock		<130,000	No	

*Fault trace within 500 m of surface infrastructure

The faults in USGS and CGS (2006) at the Kirby Hill facility are shown in Figure 1.2-10. The Kirby Hills fault is shown as passing through the field by DOG (1982). Note that the name of the field in which this facility is located is "Kirby Hill Gas," while the name of the fault is "Kirby Hills." Consequently, it may pass through some of the storage wells; however, this is uncertain because the fault appears to be almost vertical. Parsons et al. (2002) indicate earthquakes have been recorded on this fault at depth, and that to the south, the fault deforms the "youngest" sedimentary rock. A very high resolution seismic reflection profile across the fault in the Sacramento River also suggests movement on the fault has deformed sediments deposited by the river.

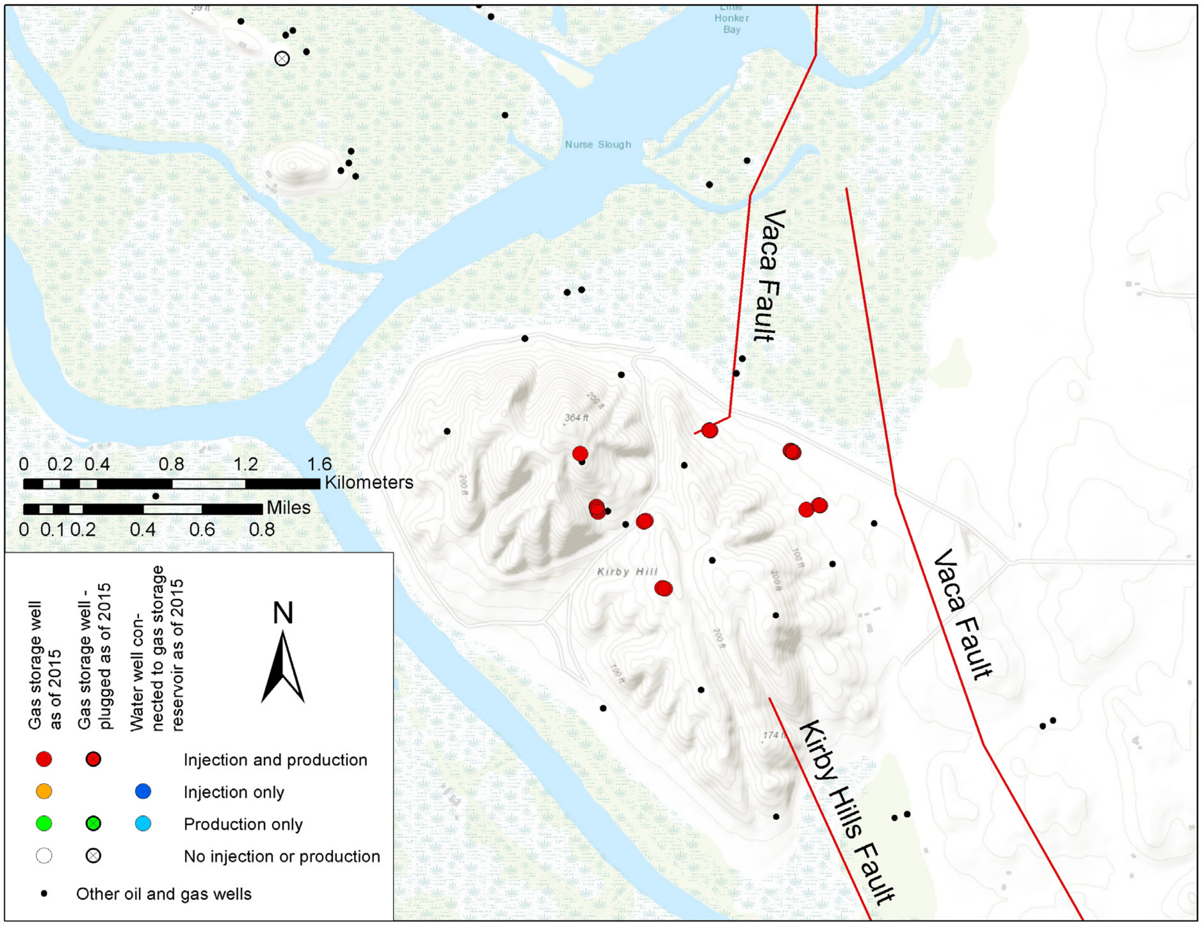


Figure 1.2-10. Vaca and Kirby Hills fault traces that ruptured in the last 130,000 years in the vicinity of the Kirby Hill facility shown in red (USGS and CGS, 2006).

The faults with surface rupture in the Quaternary in the vicinity of the Los Medanos facility are shown in Figure 1.2-11. Based on the linearity of the fault traces across topography with relief, the faults appear to be vertical, or nearly so. No vertical faults are shown on the cross section through the Main area, which is where storage is located (DOG, 1982). Consequently, there is likely no hazard of storage wells being sheared by rupture of these faults. However, the Los Medanos Hills thrust fault passes above the storage reservoir (Hoffman, 1992) and is listed as Quaternary active by Unruh and Sundermann (2006). Consequently, the storage wells are susceptible to hazard of being sheared by movement on this fault.

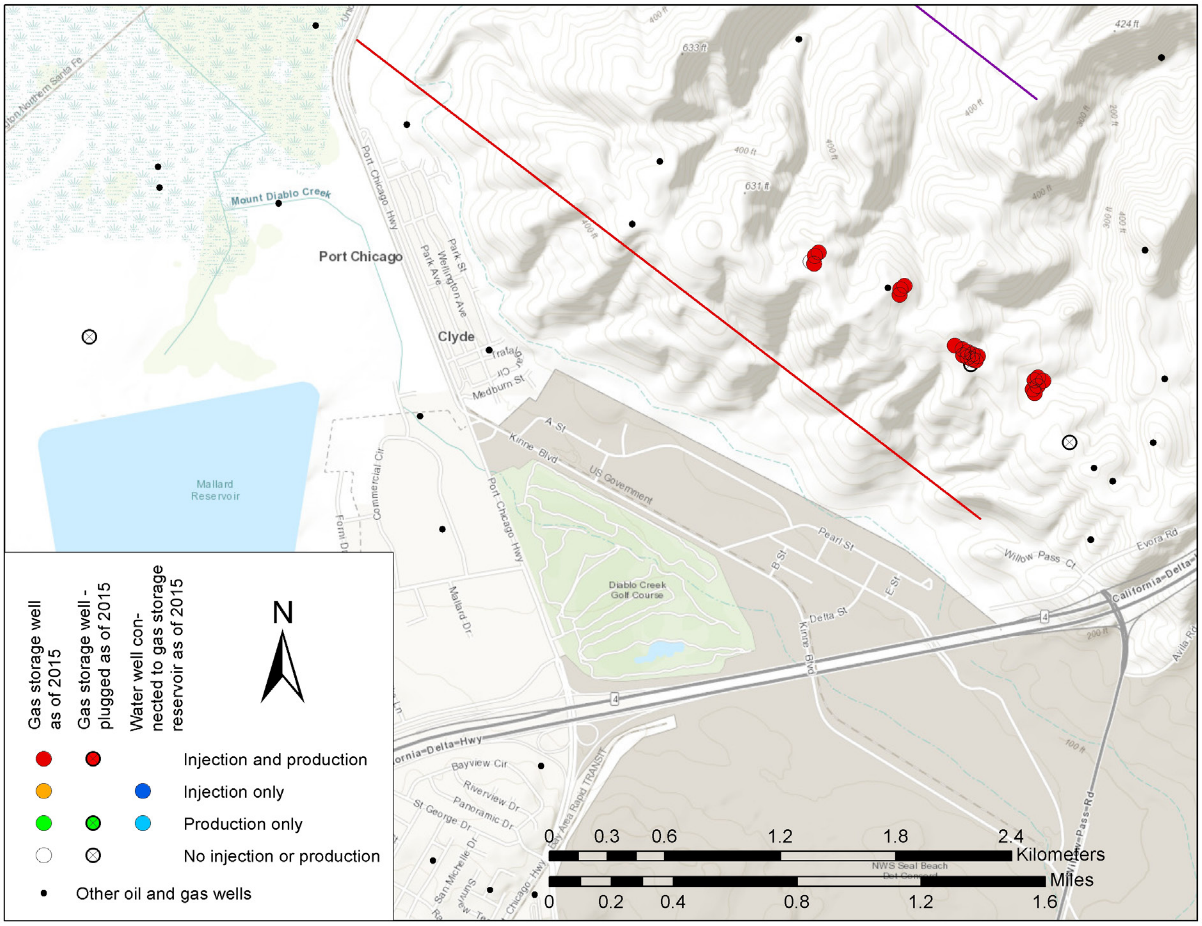


Figure 1.2-11. Unnamed fault traces that ruptured in the Quaternary in the vicinity of the Los Medanos facility. Rupture in the last 1.6 million years shown in purple and the last 130,000 years shown in red (USGS and CGS, 2006).

The EFZ at Aliso Canyon is shown in Figure 1.2-12. This EFZ corresponds to a segment of the Santa Susana fault that was active during the last 11,000 years, the surface trace of which ends just to the southeast of the facility (Figure 1.2-12). Approximately 3 km farther east, surface displacement on the Santa Susana fault occurred during the 1971 magnitude 6.5 Sylmar-San Fernando earthquake. The most recent rupture of the section of the Santa Susana fault trace that continues westward to the south of the Aliso Canyon facility and another trace through its western edge is given as occurring less than 130,000 years ago (Figure 1.2-12).

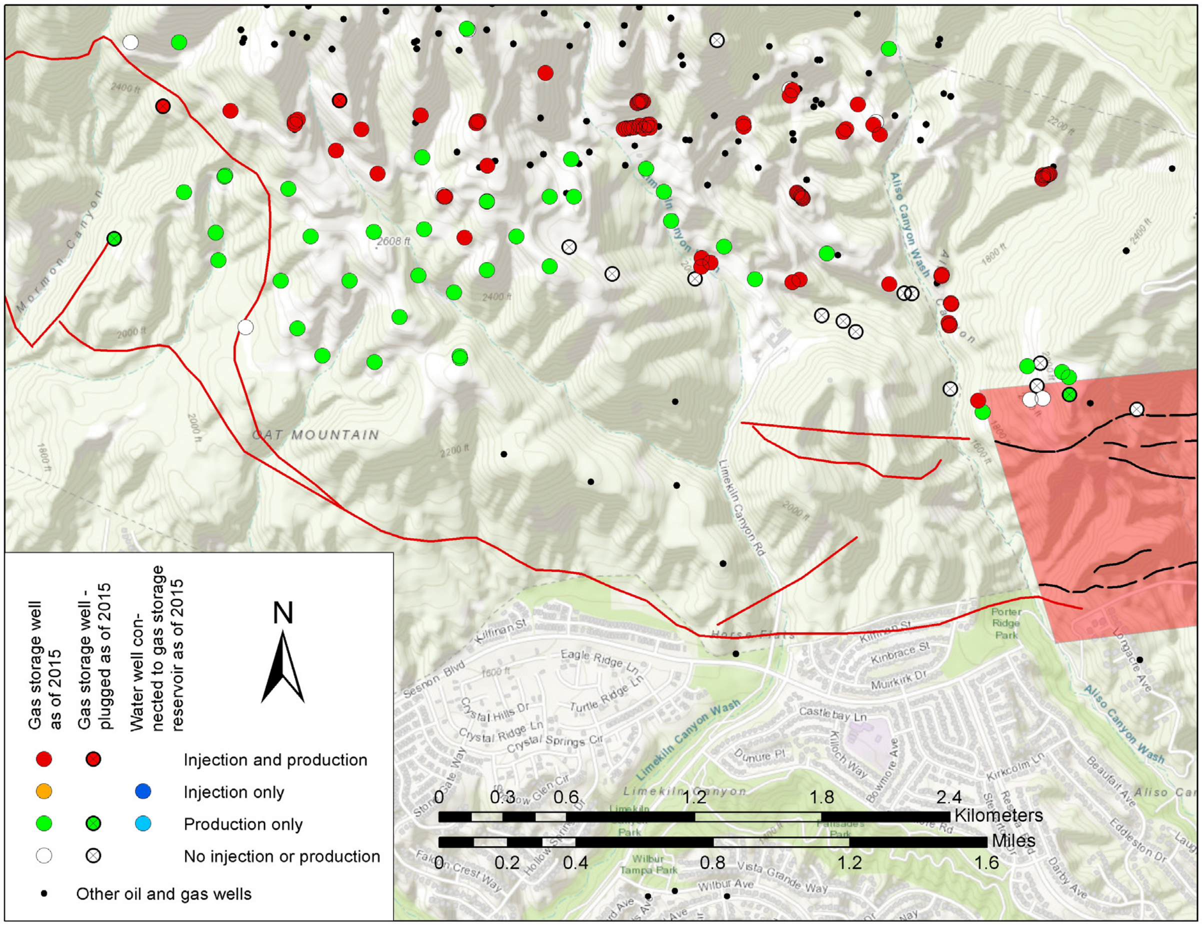


Figure 1.2-12. Earthquake Fault Zone (EFZ) at the Aliso Canyon facility shown in red tint (CGS, 1976). Fault traces that ruptured during the last 15,000 years are shown in black, and traces that show evidence for activity during the last 130,000 years are shown in red (USGS and CGS, 2006).

The long-term slip rate assigned to the Santa Susana fault in Version 3 of the authoritative Uniform California Earthquake Rupture Forecast (UCERF3; Field et al., 2014) model is 6 mm/year, which is one of the highest rates for a reverse fault in the Western U.S. However, the overall characterization of the fault is subject to significant uncertainty, and the bounds on this estimate range from 0.5 to 10 mm/year. This is because the relatively high slip rate estimate is only indirectly constrained (Huftile and Yeats, 1996; Yeats, 2001), and appears to be incompatible with the geomorphic expression of the fault. The age of latest displacement on this segment of the fault is also very poorly constrained (Lung and Weick, 1987).

The subsurface geometry of the Santa Susana fault system at Aliso Canyon is particularly well defined by abundant well data, as shown in Figure 1.2-13. Above 1.5 km depth, the system comprises three north-dipping fault strands and the associated buried Roosa and Ward faults. The Younger Santa Susana strand is considered to be the most active. While the wellheads of only two wells active in 2015 are located within the EFZ, all of the Aliso Canyon wells penetrate the Younger strand of the Santa Susana fault in the subsurface, and some of them also penetrate the Upper Older strands. It appears likely that the fault strand penetrated by the wells to the storage reservoir along the eastern margin of the facility corresponds to the surface trace mapped as active during the last 11,000 years. The maximum magnitude estimated in UCRF3 for the Santa Susana fault is 6.6 to 7.3, which corresponds to fault displacements in the approximate range of 0.5 to 2.5 meters. A portion of the interconnect is also located in the EFZ.

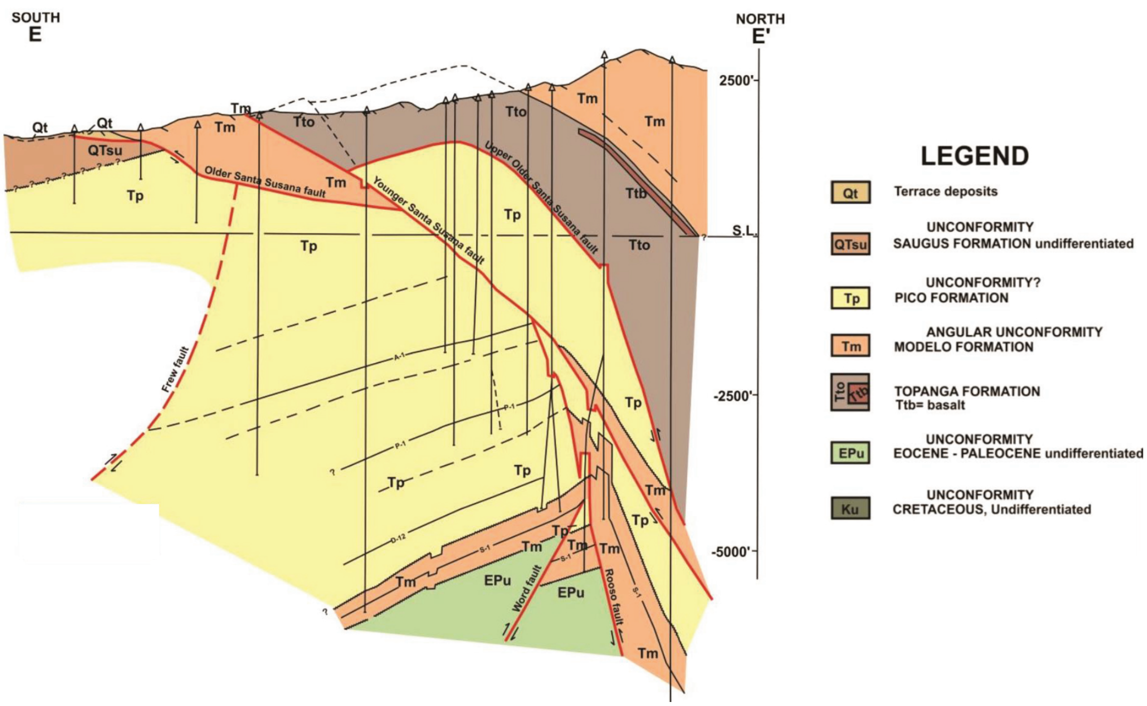


Figure 1.2-13. North-south cross section through the Aliso Canyon facility about one km west of the western end of the EFZ shown in Figure 1.2-12. Vertical lines represent wells. The storage reservoir is in the Modelo Formation (Davis et al., 2015).

The EFZ at Honor Rancho is shown in Figure 1.2-14. While only one well was open in the EFZ in 2015, the EFZ is for the San Gabriel Fault. USGS and CGS (2006) indicate displacement on this fault is dextral (the far-side moves to the right). As such, the fault surface is likely to be near vertical, although it dips to the northeast in the shallow subsurface. Therefore, it is unlikely that the portion of the fault within the EFZ intersects any active wells in the subsurface. The cross section through the Honor Rancho field Main area in DOGGR (1998), which is approximately perpendicular to the fault, does not show the fault, which tends to confirm this interpretation.

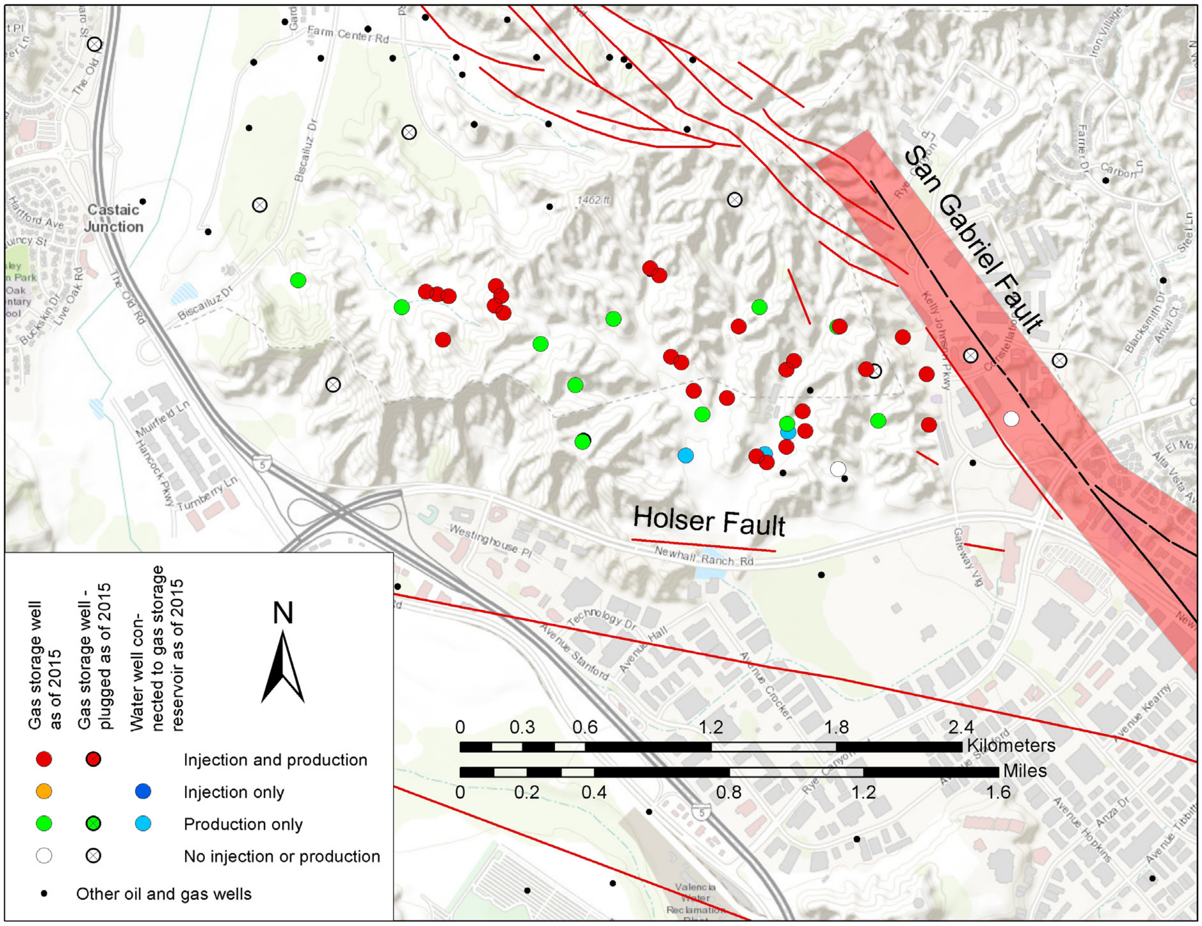


Figure 1.2-14. Earthquake Fault Zone (EFZ) at the Honor Rancho facility shown in red tint (CGS, 1995a). Fault traces ruptured in the last 11,000 years are shown in black, and traces ruptured in the last 130,000 years shown in red (USGS and CGS, 2006).

At the northern end of the Holocene-active segment shown in Figure 1.2-14, the San Gabriel fault zone bends to strike northwest with a most recent rupture in the last 130,000 years. There are short traces of the San Gabriel fault that ruptured in the last 130,000 years that are up to the margins of the facility. Rupture of these, should it occur, is more likely to intersect wells in the subsurface.

The short trace of the Holser fault is within 500 m south of the Honor Rancho facility, as shown in Figure 1.2-14. This is a south-dipping reverse fault (Jennings and Bryant, 2010). As such, it dips away from the facility and is unlikely to intersect any storage wells.

Three traces of the west-striking More Ranch fault, which last ruptured during the last 130,000 years, are mapped within 0.5 km north of the La Goleta facility (USGS and CGS, 2006), as shown in Figure 1.2-15. The More Ranch fault dips to the south (Keller and Gurrola, 2000). The fault is a section of the approximately 70 km long Mission Ridge-Arroyo Parida-Santa Ana fault system. The entire fault system is assigned a Late Quaternary long-term slip rate of 0.4 to 1.6 mm/year in the UCERF3 model, but the estimate for the More Ranch fault itself is 0.3 mm/year based on local field data. The maximum earthquake magnitude for the entire system is estimated at 6.8 to 7.3, corresponding to fault displacements of approximately one to two meters.

At storage depth, the More Ranch fault is also to the north (Olson, 1982; Davis Namson Consulting Geologists, 2005). Since all the storage wellheads in the facility are located south of the More Ranch fault traces, as shown on Figure 1.2-15, presumably none is at risk of being directly sheared by the fault due to crossing it. However, a Final Environmental Impact Report certified in 2013 regarding the proposed installation of four new wells included one that would cross the fault to test for the existence of a gas-filled trap north of the fault (Santa Barbara County Planning and Development Department, 2013). If such gas were as encountered, it would be withdrawn and then utilized for additional storage at the facility. A review of DOGGR’s well finder indicates this well (Chase and Bryce 3) does not exist, and there is no permit for its construction. However, if such a well or wells are ever developed at this facility, they would be at risk of shearing by rupture of the More Ranch fault.

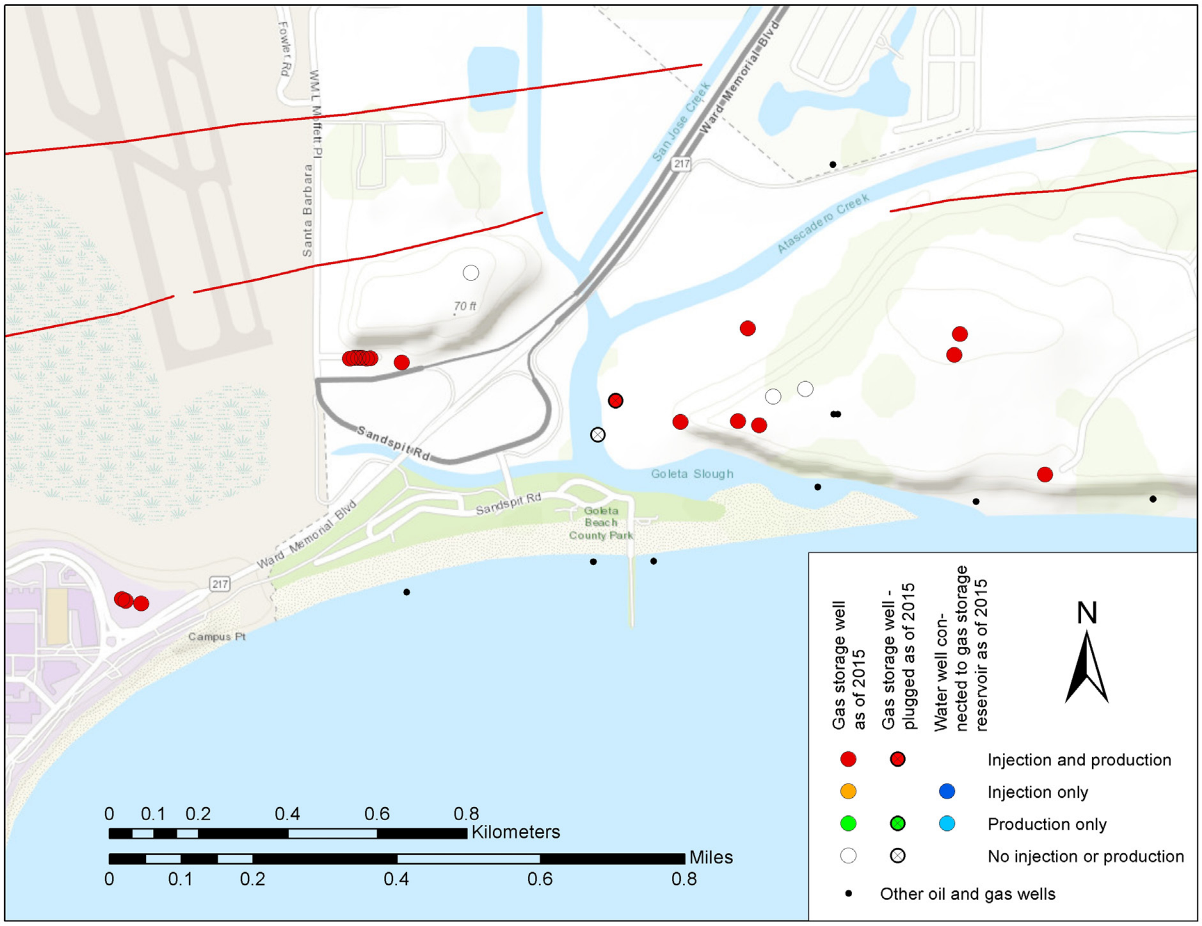


Figure 1.2-15. More Ranch fault traces north of the La Goleta facility that ruptured in the last 130,000 years shown in red (USGS and CGS, 2006).

Figure 1.2-16 shows maps of major faults and earthquake shaking potential in California. As shown, the Los Angeles Basin and nearby coastal areas have numerous faults and significant seismic hazards.

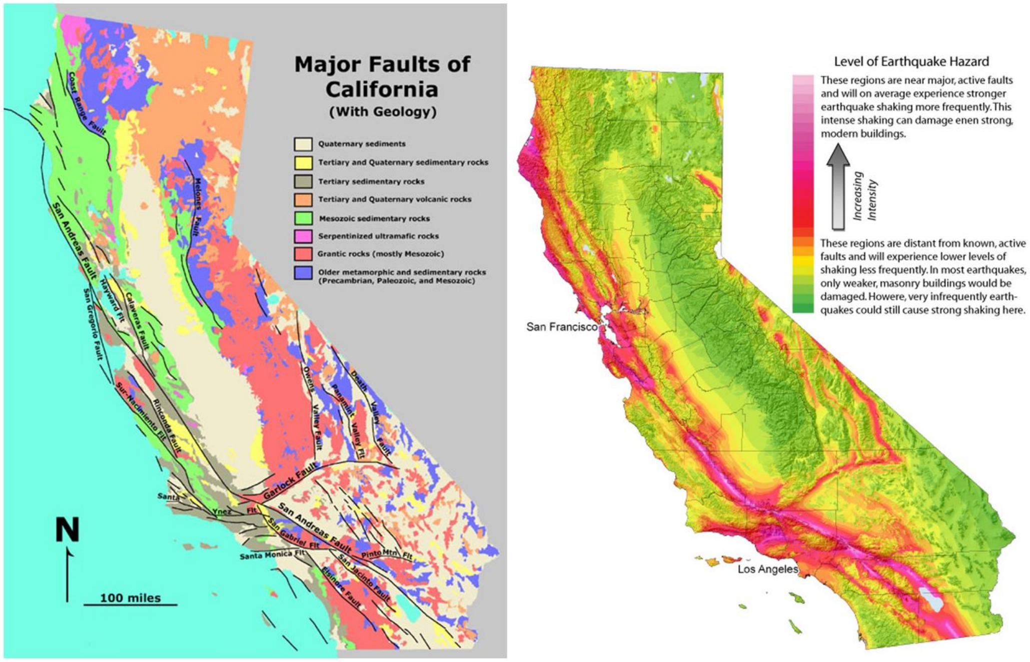


Figure 1.2-16. (a) Major faults and general geology of California (Source: http://geologycafe.com/erosion/tectonics.html accessed 7/17/17) (b) Earthquake shaking potential in California (Branum et al., 2016).

The CGS and USGS seismic hazard assessment for California include estimates of the 0.2-second spectral acceleration during earthquakes with a 2% chance of being exceeded in a 50-year period (Branum et al., 2016) and the 1.0-second spectral acceleration with the same chance of being exceeded (Branum et al., 2016). (Spectral acceleration is a standard measure related to the responses of buildings with different resonance periods. These frequencies typically correlate to building height. Taller buildings have longer resonance periods and so respond most strongly to lower frequencies.) Table 1.2-3 lists spectral accelerations for each type of surface infrastructure at each facility. Because of their different proximities to active faults, the southern California facilities have the highest anticipated accelerations, and the independently operated facilities in central and northern California, with the exception of Kirby Hills, have the lowest.

Table 1.2-3. 2% chance of spectral acceleration exceedance in 50 years (Branum et al., 2016). 0.2-second period accelerations greater than 1 g and 1.0-second period accelerations greater than 0.5 g are tinted pink. 0.2-second period accelerations greater than 2 g and 1.0-second period accelerations greater than 1.0 g are tinted light red. 1.0-second period accelerations greater than 3.0 g are tinted dark red. (g is the acceleration due to gravity.)

	Facility	Infrastructure	Spectral acceleration (fraction of g)	
			0.2-second	1.0-second
Independents	Gill Ranch Gas	Wellhead(s)	0.85	0.45
		Flowline(s)	0.85	0.45
		Plant	0.85	0.45
		Interconnect	0.85-1.45	0.45
	Kirby Hill Gas	Wellhead(s)	1.55	0.55
		Flowline(s)	1.55	0.55
		Plant	1.55	0.55
		Interconnect	1.25-1.55	0.55-0.75
	Lodi Gas	Wellhead(s)	0.65	0.35
		Flowline(s)	0.65	0.35
		Plant	0.65	0.35
		Interconnect	0.65-1.25	0.35-0.85
	Princeton Gas	Wellhead(s)	0.75	0.45
		Flowline(s)	0.75	0.45
		Plant	0.75	0.45
		Interconnect	0.75-0.95	0.35-0.55
	Wild Goose Gas	Wellhead(s)	0.65	0.45
		Flowline(s)	0.65	0.35-0.45
		Plant	0.65	0.45
		Interconnect	0.65	0.35-0.45
PG&E	Los Medanos Gas	Wellhead(s)	2.05-2.15	0.75-0.85
		Flowline(s)	2.05-2.15	0.75-0.85
		Plant	2.05-2.15	0.75
		Interconnect	2.05-2.15	0.75
	McDonald Island Gas	Wellhead(s)	1.15	0.75
		Flowline(s)	1.15	0.75
		Plant	1.15	0.75
		Interconnect	1.15-1.25	0.55-0.85
	Pleasant Creek Gas	Wellhead(s)	1.75	0.85
		Flowline(s)	1.75-1.85	0.75-0.85
		Plant	1.85	0.75
		Interconnect	1.85	0.65-0.75

	Facility	Infrastructure	Spectral acceleration (fraction of g)	
			0.2-second	1.0-second
SoCalGas	Aliso Canyon	Wellhead(s)	2.45-2.55	1.45
		Flowline(s)	2.45-2.55	1.45
		Plant	2.55	1.45
		Interconnect	2.45-2.75	1.15-1.45
	Honor Rancho	Wellhead(s)	2.25-2.45	0.95-1.15
		Flowline(s)	2.25-2.45	0.95-1.15
		Plant	2.45	1.05
		Interconnect	2.45	1.05
SoCalGas	La Goleta Gas	Wellhead(s)	2.65	1.45-1.55
		Flowline(s)	2.65	1.45-1.55
		Plant	2.65	1.45
		Interconnect	2.65	1.45
	Playa del Rey	Wellhead(s)	1.35-1.65	0.75-0.95
		Flowline(s)	1.35-1.65	0.75-0.95
		Plant	1.35-1.55	0.75-0.95
		Interconnect	1.35-1.55	0.75-0.95

The CGS has mapped Liquefaction and Earthquake-induced Landslide Zones throughout most of the urbanized portions of the Los Angeles Basin, Antelope Valley, San Francisco Peninsula, East San Francisco Bay Area, and South San Francisco Bay Area. These ground deformations can damage both surface and subsurface infrastructure. As such, certain structures, such as buildings with multiple residences that are proposed within these Seismic Hazard Zones (SHZs) must conduct a site-specific investigation to identify if the hazard is present, and if so to mitigate the hazard.

Table 1.2-4 lists which UGS facilities have been mapped for SHZs, and for those facilities each class of surface infrastructure in each type of SHZ. For the facilities not in SHZs, the presence or absence of the hazard is estimated based upon the geologic and geomorphic setting. While each of the independently operated facilities is estimated to have one or both hazards, the probability of those hazards occurring at all of them but Los Medanos is lower than for the other facilities, because ground shaking is estimated to be lower. Figure 1.2-17 shows the SHZs at the facilities for which they have been mapped.

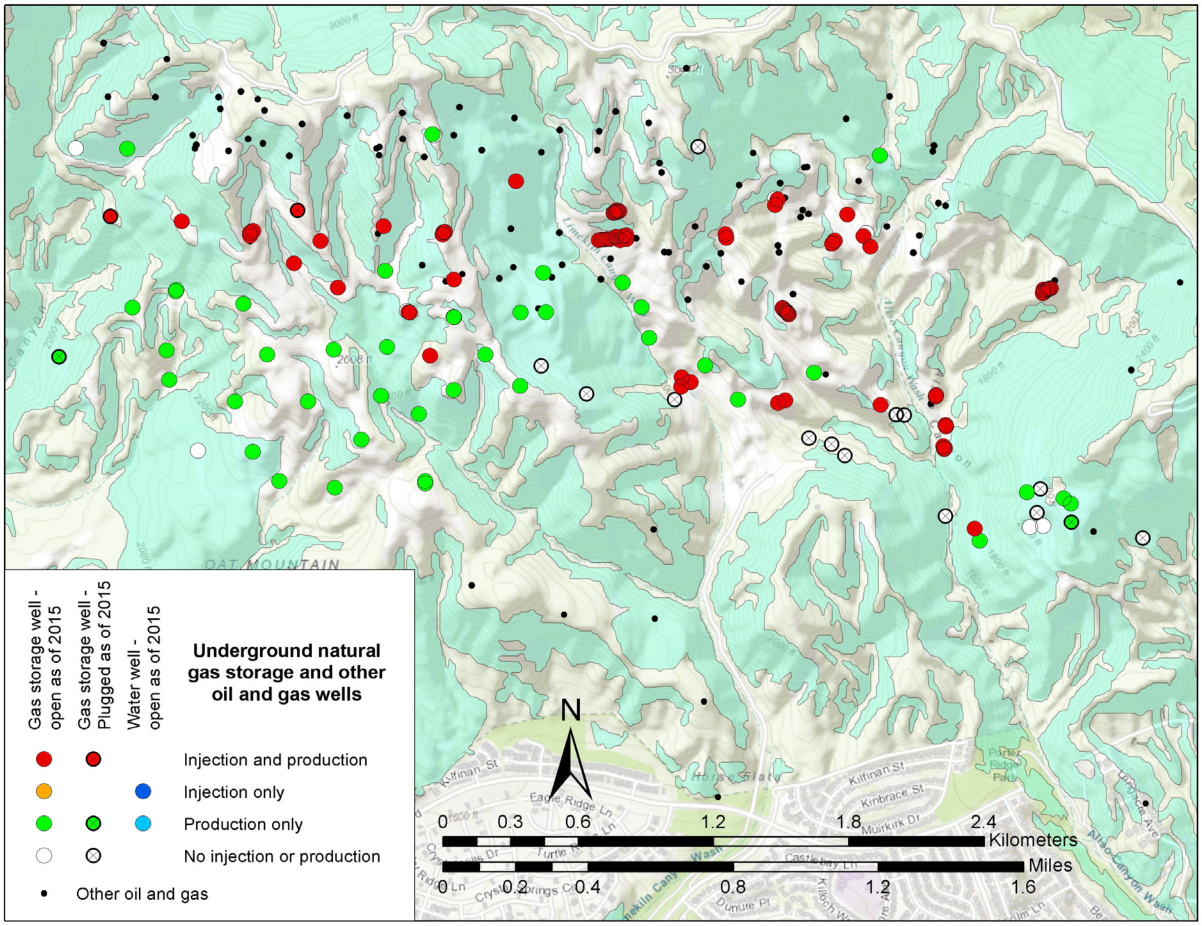
Table 1.2-4. UGS surface infrastructure in Seismic Hazard Zones by facility and type of zone.

	Facility	Infrastructure	Seismic Hazard Zone	
			Liquefaction	**Earthquake-induced landslide**
Independents	Gill Ranch Gas	All	? (unmapped, but includes alluvium by a river)	No (unmapped, but little topographic relief)
	Kirby Hill Gas	All	? (unmapped, but includes alluvium by a slough)	? (unmapped, but includes hillslopes)
	Lodi Gas	All	? (unmapped, but includes alluvium by a slough)	No (unmapped, but little topographic relief)
	Princeton Gas	All	? (unmapped, but includes alluvium by a river)	No (unmapped, but little topographic relief)
	Wild Goose Gas	All	? (unmapped, but includes alluvium by a river)	No (unmapped, but little topographic relief)
PG&E	Los Medanos Gas	All	No (unmapped, but no alluvium or shallow saturation)	? (unmapped, but includes hillslopes)
	McDonald Island Gas	All	? (unmapped, but includes alluvium by a slough)	No (unmapped, but little topographic relief)
	Pleasant Creek Gas	All	? (unmapped, but includes alluvium by a river)	No (unmapped, but little topographic relief)
SoCalGas	Aliso Canyon1	Well(s) and flowline(s)	No	Yes
		Plant	No	No
		Interconnect	Yes	Yes
	Honor Rancho2	Well(s) and flowline(s)	Yes	Yes
		Plant	Yes	No
		Interconnect	Yes	No
	La Goleta Gas	All	? (unmapped, but includes alluvium by a slough and shore)	? (unmapped, but includes bluffs)
	Playa del Rey3	Well(s) and flowline(s)	Yes	Yes
		Plant	Yes	Yes
		Interconnect	Yes	No

1 CGS (1998b);

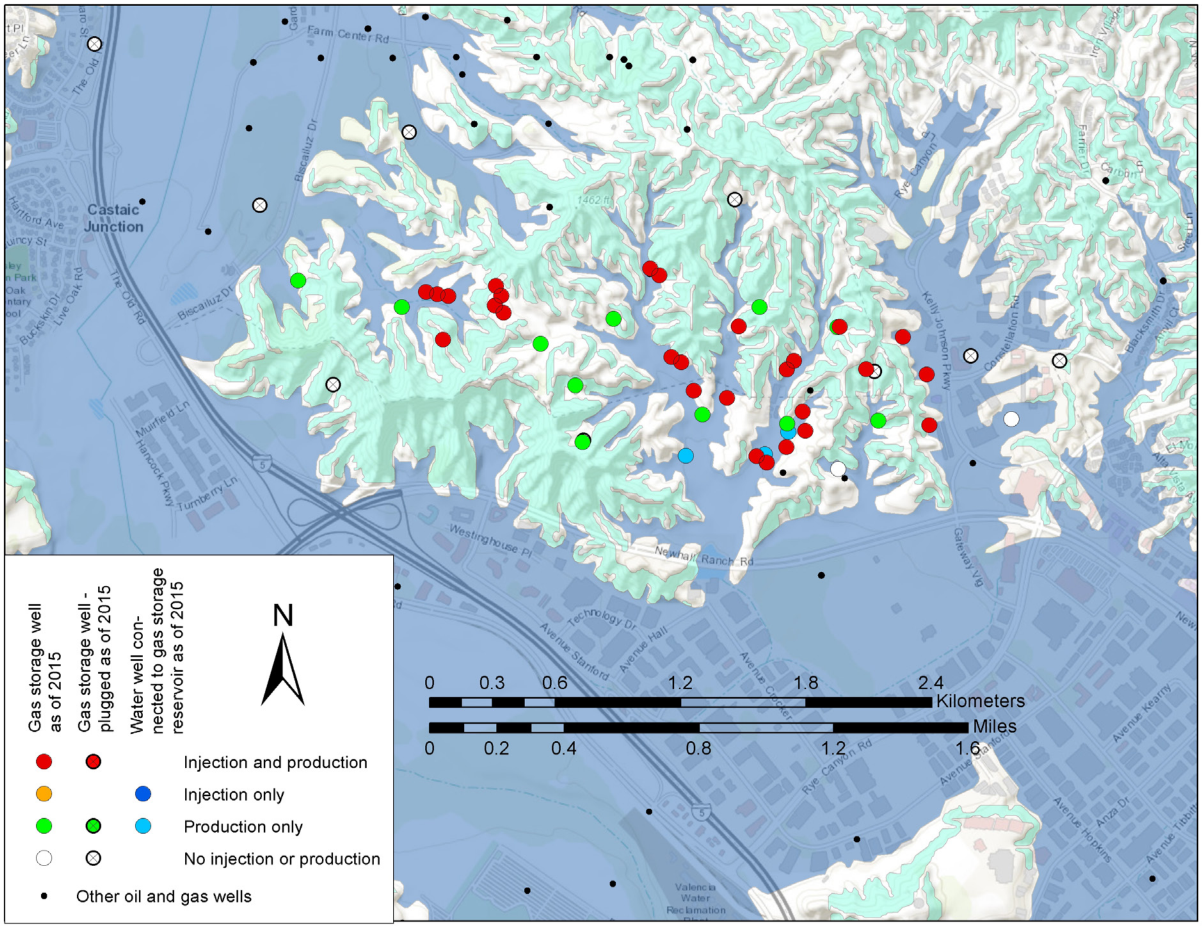
2 CGS (1998a);

3 CGS (1995a,b)

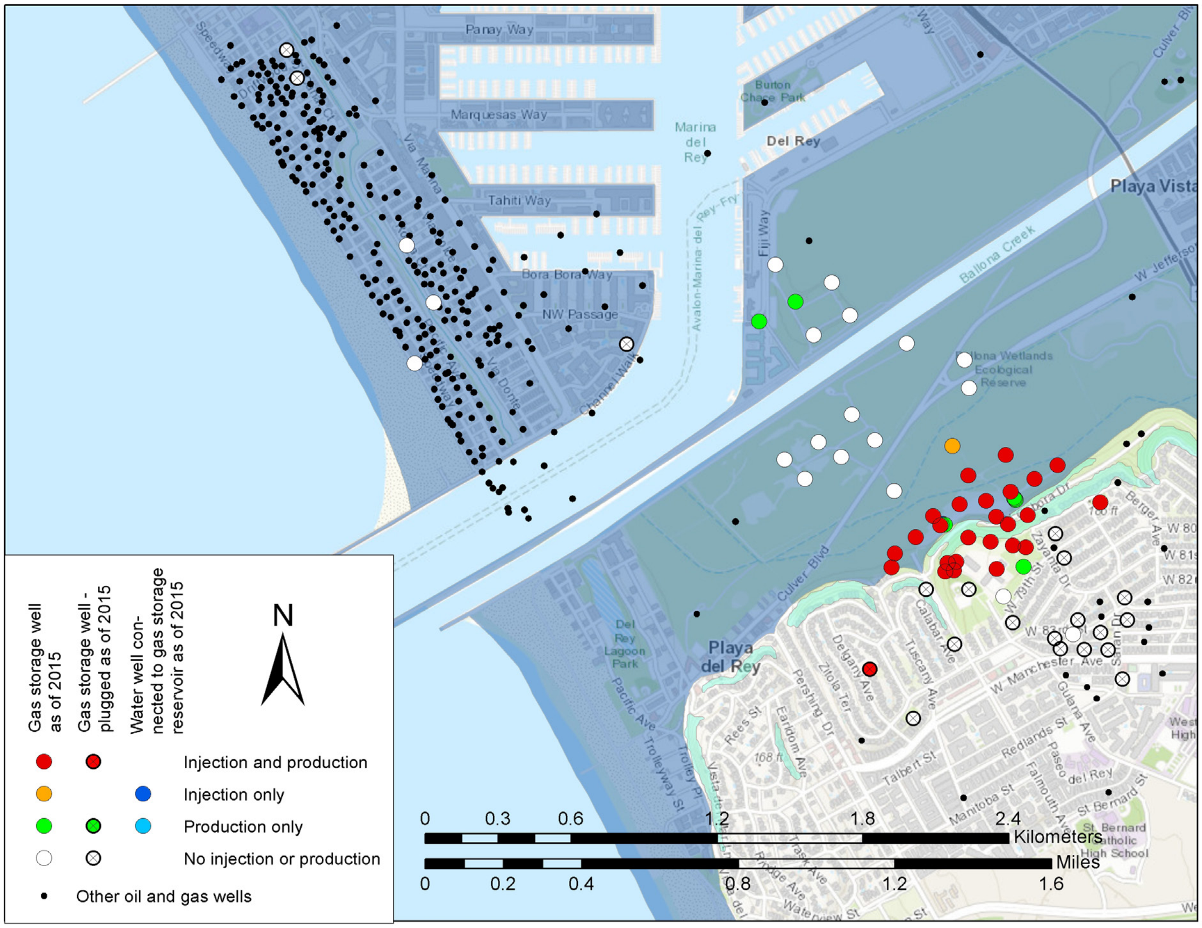


Gas storage well - open as of 2015
Gas storage well - Plugged as of 2015
Water well - open as of 2015
Underground natural gas storage and other oil and gas wells
Injection and production
Injection only
Production only
No injection or production
Other oil and gas
N
0 0.3 0.6 1.2 1.8 2.4 Kilometers
0 0.2 0.4 0.8 1.2 1.6 Miles
OAT MOUNTAIN

(a)


Gas storage well as of 2015
Gas storage well - plugged as of 2015
Water well connected to gas storage reservoir as of 2015
N
Injection and production
Injection only
Production only
No injection or production
Other oil and gas wells
0 0.3 0.6 1.2 1.8 2.4
Kilometers
0 0.2 0.4 0.8 1.2 1.6
Miles
Castaic Junction
Farm Center Rd
Biscailuz Dr
Newhall Ranch Rd
Kelly Johnson Pkwy
Rye Canyon Rd
Westinghouse Pl
Technology Dr
Avenue Stanford
Avenue Hall
Turnberry Ln
Muirfield Ln
Hancock Pkwy
The Old Rd
Constellation Rd
Gateway Vlg
Avenue Hopkins
Anza Dr
Avenue Kearny
Valencia Water Reclamation

(b)



(c)

Figure 1.2-17. Seismic Hazard Zones at the (a) Aliso Canyon (CGS, 1998b), (b) Honor Rancho (CGS, 1998a), and (c) Playa del Rey (CGS, 1995b) facilities. Liquefaction Zones shown in dark blue tint and Earthquake-Induced Landslide Zones in light blue tint.

UGS incidents arising from earthquake activity are not entirely hypothetical. The following text is from the Supplement to SoCalGas' Storage Risk Management Plan #2 (SoCalGas, 2016b):

> *"The 1994 Northridge earthquake damaged the surface terrain at the Aliso Canyon facility, including landslides, cracked well cellars and roads, tank farm damage, and pipe support damage. An immediate investigation of storage well integrity following the earthquake indicated that only one well -SS4-O- was affected, and it experienced a collapsed casing in a section above the gas storage zone. A work-over rig repaired the damaged well and, with regulatory oversight provided by DOGGR, SoCalGas successfully drilled around the damaged section and placed abandonment cement below the collapse and into the storage zone. SoCalGas recovered a section of the casing*

> *and noted that the collapsed casing sealed the well. The well was subsequently plugged in accordance with DOGGR plug and abandonment regulations.*
>
> *Since the 1994 Northridge earthquake, there have been no incidents of casing failure from seismic events at the Aliso Canyon facility."*

The reported sealing of the well by the collapsed casing suggests that no LOC occurred during this incident. Regardless, in other scenarios, wells could fail in ways that lead to LOC, and certainly surface infrastructure is vulnerable to damage. Therefore, UGS facilities in California should assess seismic hazard with respect to shaking and fault displacement and implement mitigation measures such as base isolation for foundations, seismic bracing, automatic seismic shut-off valves, etc.

SoCalGas is currently conducting a comprehensive hazard and risk assessment for the Aliso Canyon facility employing state-of-the art methodologies (Harris et al., 2017). The probabilistic seismic (ground shaking) hazard analysis (PSHA) utilizes the same technique used by CGS and USGS to develop the seismic hazard maps described above, but on a site-specific basis. This assessment is based on data for all relevant fault sources in the UCERF3 database, with extensive additional detailed characterization of faults within the facility and in its immediate vicinity. Estimates of local amplification of ground shaking caused by differences in surface geology at locations within the site are included in the analysis. A probabilistic fault displacement hazard assessment (PFDHA) is being carried out employing an analysis approach developed for other critical facilities adapted to include subsurface fault displacement. The PFDHA as applied at Aliso Canyon utilizes the fault characterizations developed for the PSHA and estimates of fault slip derived from earthquake magnitudes. The fault geometries and slip rates that form the inputs to these assessments are usually subject to significant uncertainties, often stemming from alternative interpretations of sparse available data. Therefore, an important aspect of both PSHA and PFDHA is rigorous treatment of these uncertainties to enable realistic uncertainty bounds on the hazard to be estimated.

The landslide hazard at Aliso Canyon is being addressed by extensive field investigations of existing and potential landslide zones. These include both surface mapping and gathering data from purpose-designed trenches to characterize and date recurring landslide events. Comprehensive structural geology, and petrophysical and geomechanical analyses are being conducted to provide the basis for assessment of risks, including gas leakage through faults and well failure. Although most sites are not subject to all of the hazards considered at Aliso Canyon, specific items from the suite of investigations being carried out there can serve as models for application to other UGS facilities.

1.2.3.8 Tsunami

1.2.3.8.1 Introduction

Tsunamis are sea waves generated by large displacements of water that can cause rapid inundation, followed by outwash, and related damage to low-lying coastal areas. In California, tsunamis can be caused by (1) distant and local earthquakes, and (2) by subsea landslides (Thio et al., 2010; Dooher, 2016). The force of water in the sea wave itself, or insofar as it can carry heavy debris capable of crashing into surface infrastructure, can cause catastrophic damage to UGS components such as pipelines, wellheads, compressors, etc. As such, the main mode of failure of concern for UGS sites is damage by impact from water or heavy debris on pipelines, wellheads, and other surface infrastructure. A secondary mode of failure is erosion and/or undermining of support structures and foundations holding surface infrastructure.

The UGS facilities in California that are vulnerable to marine tsunamis are the La Goleta and Playa del Rey facilities, located in Goleta (approx. 10 mi (16 km) from Santa Barbara) and Playa del Rey (near Venice Beach), as shown on Figure 1.2-18. Some of the wells and flowlines in the La Goleta UGS facility are within the projected inundation zone. The only facilities within the inundation zone at the Playa del Rey facility are in a few wells in Venice Beach north of the Ballona Creek estuary, which flows into the Pacific. These wells were open in 2015, but no gas was transferred through them in the 2006 through 2015 study period, suggesting they are observation wells. As such, they may not have flowlines connected, or, if present, the lines may not be charged with gas. However, these wells presumably connect to the storage reservoir, and so damage to them by a tsunami could potentially result in an LOC incident.

Figure 1.2-18. Maps showing potential tsunami inundation areas in pink for emergency planning: a) covering the La Goleta facility, which stretches from on bluffs east of the tsunami inlet to the bluffs west of the tsunami inlet (California Emergency Management Agency [CEMA] et al., 2009a), and (b) covering the Playa del Rey facility, whose surface facilities are primarily south of the channel near the bluffs (CEMA et al., 2009b).

1.2.3.8.2 Seismically Generated Tsunamis

Thio et al. (2010) used computational approaches to model seismically generated tsunamis along the Central California coast with consideration of both aleatory uncertainty (random uncertainty that generally cannot be reduced) and epistemic uncertainty (uncertainty related to properties that can be reduced by data collection and better understanding). Results of their modeling relevant to the La Goleta and Playa del Rey UGS facilities are shown in Figure 1.2-19 in plots of frequency of tsunamis of given waveheights for cities of Santa Barbara and Venice, California, respectively. The blue curves represent the hazard curve including aleatory uncertainty, while the red curves assume no aleatory uncertainty. As shown, seismically generated tsunamis with waveheights of 1 m and 2 m have return periods of approximately 200 and 1,000 yrs, respectively. We note that floating debris carried by the tsunami are a hazard of tsunami flooding because of the threat of physical impact to wellheads and related UGS infrastructure.

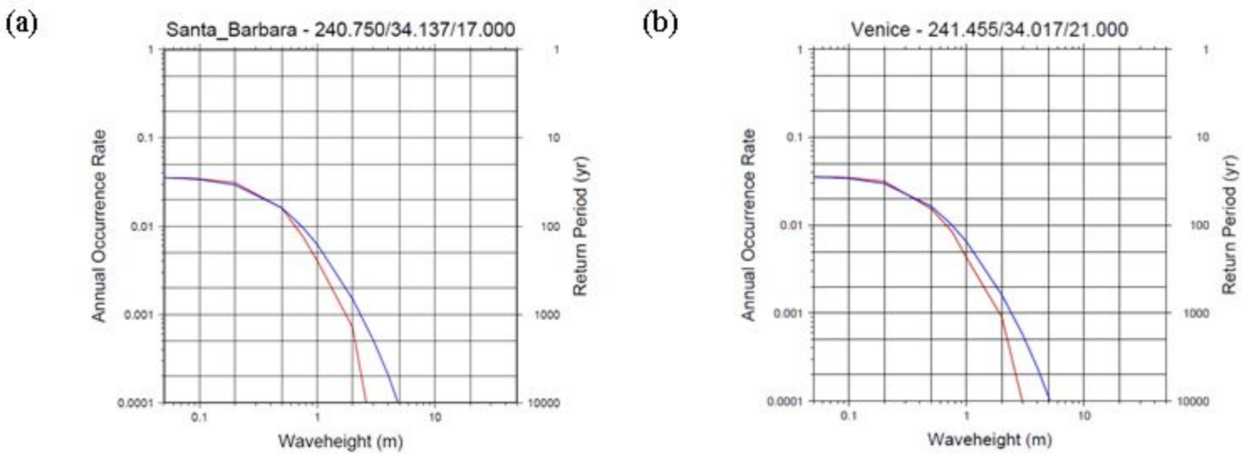


Figure 1.2-19. Modeled results of seismically generated tsunami waveheight frequency for Santa Barbara and Venice, California. A 1 m waveheight tsunami is predicted to have a recurrence interval (return period) of approximately 200 yrs.

1.2.3.8.3 Submarine Mass Failure Tsunamis

Dooher (2016) presented results of the analysis of tsunamis generated along the Central California coast by submarine mass failures (a.k.a. submarine landslides). Bathymetric mapping of the seafloor along the coast of the Santa Lucia escarpment, along with seismic reflection and core studies, allow the dating of subsea landslides. Onshore geologic evidence of tsunamis and historical records complement the offshore studies to produce defensible predictions of tsunami hazard. Shown in Figure 1.2-20 is a map of the Central California coast from Dooher (2016) showing estimated waveheights from various submarine mass failures (in red) along with official NOAA records of historical tsunami-related runups. Note that in 1812, there was a runup in Gaviota, approximately 23 mi (37 km) west of Goleta. Note further that NOAA records an official wave runup height of 8.2 ft (2.5 m) at Goleta.

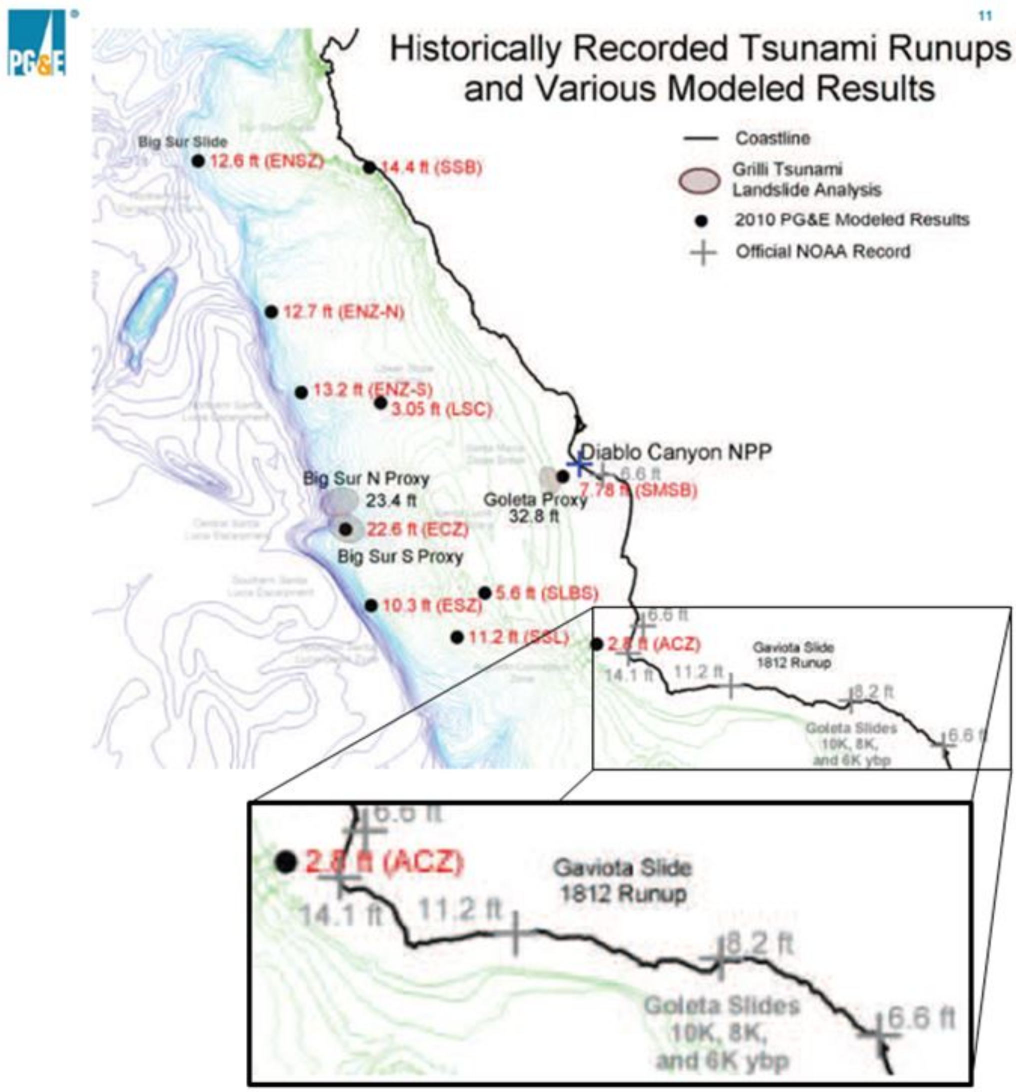


Figure 1.2-20. Historical and modeled results of tsunamis along the Central California coast after Dooher (2016). Note the 8.2 ft official NOAA record of runup at Goleta.

1.2.3.9 Flooding

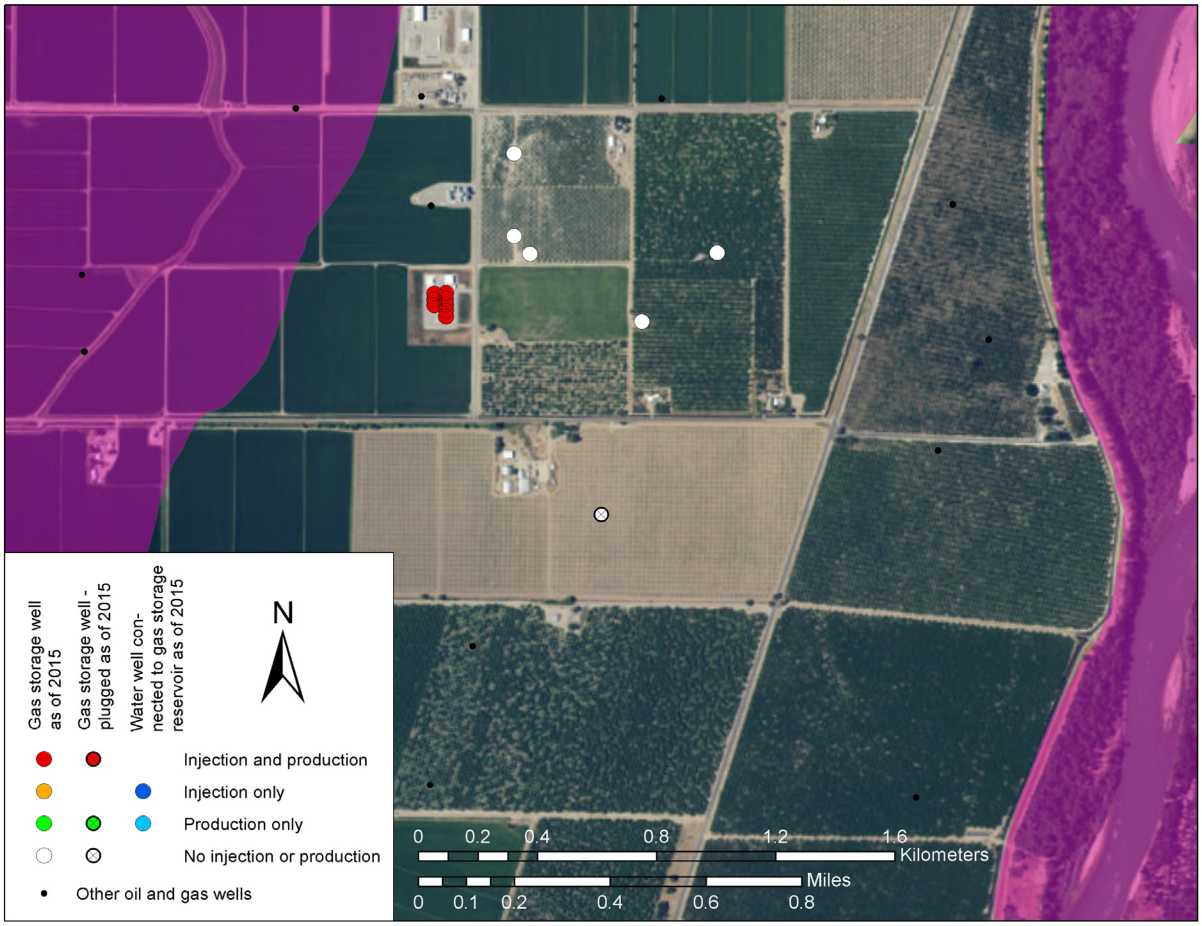
While the facilities with substantial topographic relief are generally subject to landslide hazard, facilities with little topographic relief potentially are subject to substantial risk of flooding. Like tsunamis, floods can damage UGS surface infrastructure through impact by entrained debris and erosion. Flooding also can result in a longer period of submergence than tsunamis, cutting off or making difficult access to valves and other controls. This can interfere with a facility's ability to meet its purpose serving demand, even if no other damage occurs.

The Federal Emergency Management Agency (FEMA) maps predicted flood frequency. Table 1.2-5 lists the type of infrastructure in each facility that resides within areas with an estimated 1% annual probability of flooding. We note that these maps are known to underestimate the extent of this risk. For instance, they do not consider changing hydraulics and hydrology due to development nor changing precipitation patterns and sea level due to climate change (Highfield et al., 2013).

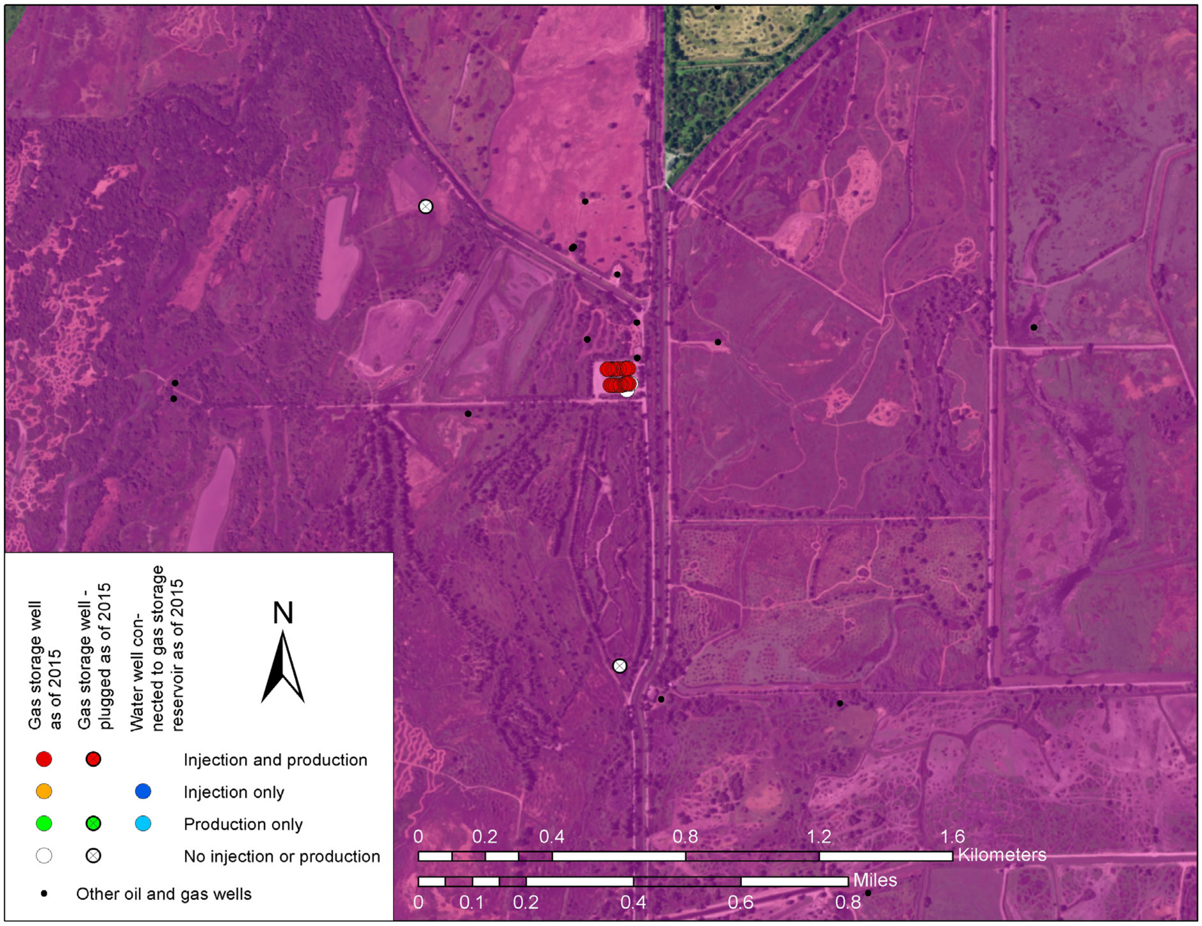
Table 1.2-5. UGS surface infrastructure in areas with an estimated 1% annual probability of flooding.

	Facility	Well(s) and flowline(s)	Plant	Interconnect	Source
Independents	Gill Ranch Gas[1, 2]	No	No	Yes	[1]FEMA (2016a) [2]FEMA (2017a)
	Kirby Hill Gas[3]	No	No	Yes	[3]FEMA (2016b)
	Lodi Gas[4, 5]	No	No	Yes	[4]FEMA (2017b) [5]FEMA (2016c)
	Princeton Gas[6]	No	Yes	Yes	[6]FEMA (2015)
	Wild Goose Gas[7]	Yes	No	Yes	[7]FEMA (2011)
PG&E	Los Medanos Gas[8]	No	No	No	[8]FEMA (2017c)
	McDonald Island Gas[4, 8]	Yes	Yes	Yes	[4]FEMA (2017b) [8]FEMA (2017c)
	Pleasant Creek Gas[9]	No	No	No	[9]FEMA (2017d)
SoCalGas	Aliso Canyon[10]	No	No	No	[10]FEMA (2016d)
	Honor Rancho[10]	No	No	No	[10]FEMA (2016d)
	La Goleta Gas[11]	Yes	No	No	[11]FEMA (2016e)
	Playa del Rey[10]	No	No	No	[10]FEMA (2016d)

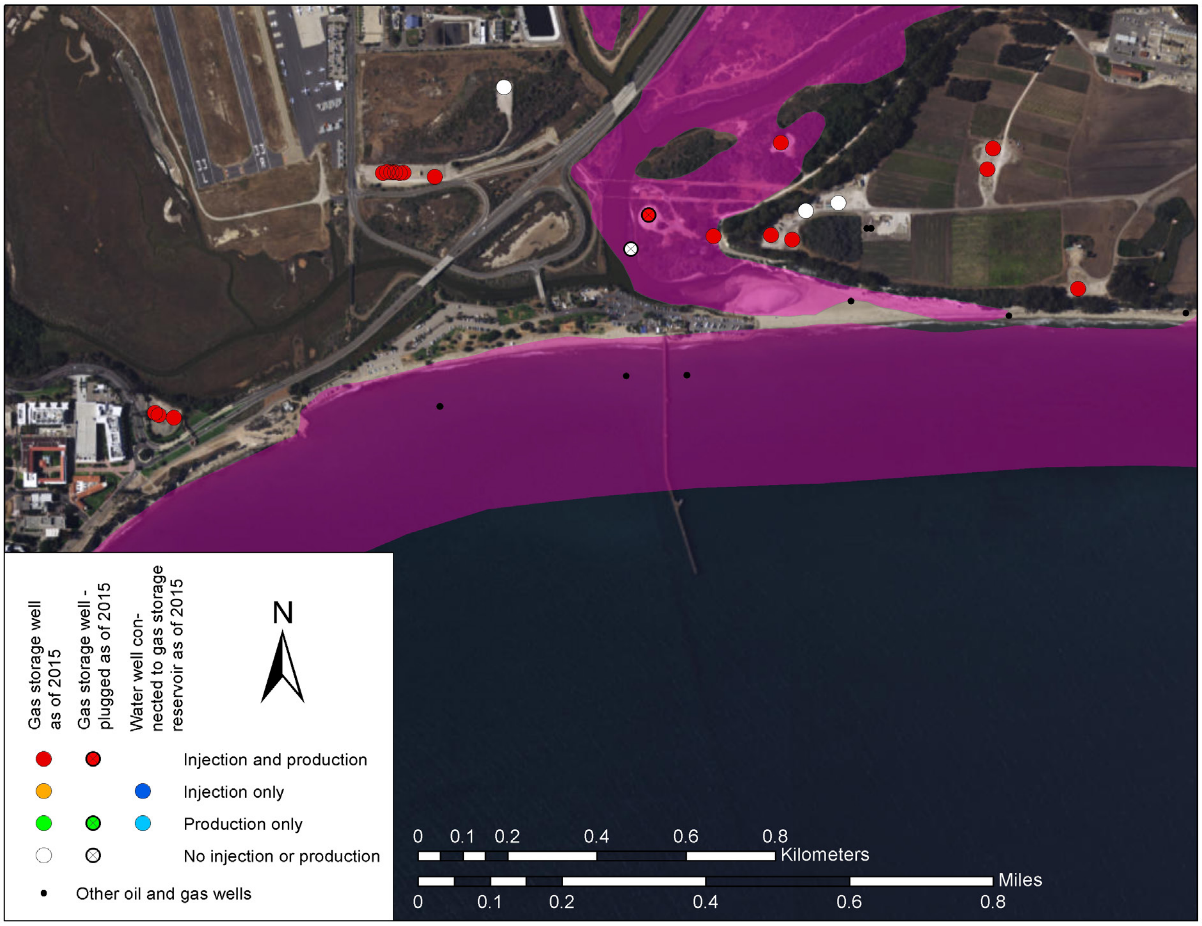
The 1% annual probability flood zones are shown on Figure 1.2-21 for facilities with well(s), flowline(s), or plant(s) in the zone other than McDonald Island. McDonald Island is not shown because it is entirely in a flood zone along with the surrounding area. This being so, most of the plant infrastructure at McDonald Island are all on elevated platforms to reduce the risk of flooding. Also of note, only an apparently unoccupied and relatively small portion of the plant at the Princeton Gas facility is in this flood zone, as shown in Figure 1.2-21a.


Gas storage well as of 2015
Gas storage well - plugged as of 2015
Water well con-nected to gas storage reservoir as of 2015
N
Injection and production
Injection only
Production only
No injection or production
Other oil and gas wells
0
0.2
0.4
0.8
1.2
1.6
Kilometers
Miles
0
0.1
0.2
0.4
0.6
0.8

(a)


Gas storage well as of 2015
Gas storage well - plugged as of 2015
Water well connected to gas storage reservoir as of 2015
N
Injection and production
Injection only
Production only
No injection or production
Other oil and gas wells
0 0.2 0.4 0.8 1.2 1.6 Kilometers
0 0.1 0.2 0.4 0.6 0.8 Miles

(b)



(c)

Figure 1.2-21. Select facilities partially in zones with a 1% annual probability of flooding according to FEMA: (a) Princeton Gas (FEMA, 2015), (b) Wild Goose Gas (FEMA, 2011), and (c) La Goleta Gas (FEMA, 2016e). Flooding zones shown in a purple tint. Note the plant at Princeton Gas (a.k.a. Central Valley Gas) is located north of the well field. The northwest corner of the plant site is within the flood zone.

1.2.3.10 Sea-level Rise

Sea level is predicted to rise along the California coast at La Jolla by ~5-7 in (12-18 cm) by 2030, and by ~8.4-14 in (21-37 cm) by 2050 relative to the 1991-2009 mean sea level, as shown in Figure 1.2-22 (Griggs et al., 2017). Flooding caused by sea-level rise is a hazard for the low-lying UGS sites in California, which include La Goleta, Playa del Rey, and McDonald Island. Given that all of these sites currently mitigate against flooding, global sea-level rise is not expected to be a major risk factor for UGS in California through 2050. Projections for beyond 2050 are more uncertain, but clearly raise the possibility that much more extensive mitigations will be necessary to operate the four low-lying facilities.

Feet above 1991-2009 mean	MEDIAN	LIKELY RANGE	1-IN-20 CHANCE	1-IN-200 CHANCE
Year / Percentile	50% probability SLR meets or exceeds...	67% probability SLR is between...	5% probability SLR meets or exceeds...	0.5% probability SLR meets or exceeds...
2030	0.5	0.4 — 0.6	0.7	0.9
2050	0.9	0.7 — 1.2	1.4	2.0
2100 (RCP 2.6)	1.7	1.1 — 2.5	3.3	5.8
2100 (RCP 4.5)	2.0	1.3 — 2.8	3.6	6.0
2100 (RCP 8.5)	2.6	1.8 — 3.6	4.6	7.1
2100 (H++)	10			
2150 (RCP 2.6)	2.5	1.5 — 3.9	5.7	11.1
2150 (RCP 4.5)	3.1	1.9 — 4.8	6.5	11.8
2150 (RCP 8.5)	4.3	3.0 — 6.1	7.9	13.3
2150 (H++)	22			

Figure 1.2-22. Forecasted sea-level rise relative to 1991-2009 mean for various times in the future. As shown, the most likely projected sea-level rise for California for 2030 ranges from 0.4-0.6 ft (12-18 cm) and approximately twice this for 2050 (Griggs et al., 2017).

1.2.3.11 Land Subsidence

Land subsidence is a well-recognized threat to infrastructure such as pipelines (e.g., Baum et al., 2008) and wells (e.g., Bruno, 2001), making it a substantial hazard for UGS surface and subsurface systems. Land subsidence in California occurs by loss of porosity and/or rearrangement of clastic sediments due typically to groundwater withdrawals, and in the California Delta region by oxidative decomposition of peat and other organic matter as a result of reclamation of wetlands and related drying (Rojstaczer et al., 1991). The modes of failure that occur as a result of land subsidence include shearing and buckling of wells, cracks, and displacement of surface infrastructure that can rupture flowlines and lead to LOC. Land subsidence is common in California's San Joaquin Valley, Delta, and Sacramento Valley areas. As such, land subsidence is a hazard to the Gill Ranch, Lodi, McDonald Island, Wild Goose, and Central Valley Storage facilities.

1.2.3.12 Wildfire

Wildfires are a serious hazard for the surface infrastructure at UGS facilities in California, regardless of whether the fire is started at the site by activities or incidents associated with the facility (e.g., welding, or ignition of released natural gas) or whether they were started externally by any cause and burn into the footprint of any UGS facility infrastructure. Several of California's UGS facilities are located in areas of grass and brush that become very dry in the summer and early fall. There are also dry northeasterly winds in California (so-called Santa Ana winds) that periodically blow particularly in southern California, causing severe fire hazard because of their typically low humidity.

Although the aboveground flowlines, wellheads, and related noncombustible hardware spread around UGS facilities will likely withstand grassfires because they are relatively fast moving and grass does not provide a lot of fuel, standard practice is to establish and maintain breaks in all vegetation around aboveground pipes and wellheads, and to maintain space between buildings and surface infrastructure. Bare ground and open spaces provide both protection for the pipe from heat impacts of direct or indirect contact with burning vegetation, and it also provides defensible space for firefighters to protect vulnerable infrastructure. Because fire of any kind is such an obvious hazard at UGS facilities, existing compressors, gas processing, and/or power plants at UGS facilities in California are located on pads maintained devoid of vegetation and with buffer zones around the perimeter. Practical and useful wildfire information related to oil and gas infrastructure can be found in the document, "READY, SET, GO! For Oil and Natural Gas Operations" http://vcfd.org/images/ready-set-go/Ready_Set_Go_Oil__Gas_2013_sm.pdf
(accessed 7/25/17).

The California Department of Forestry and Fire Protection (Cal Fire) has mapped fire hazard severity zones in its area of jurisdiction throughout the state, and has also drafted or recommended such zones for selected areas where local fire agencies are responsible for non-urban areas. Table 1.2-6 lists the predominant and maximum fire-hazard severity zone at each type of surface infrastructure.

Table 1.2-6. Predominant (and maximum, if different) fire hazard severity zones for each type of surface infrastructure at each UGS facility in California from Cal Fire (2007a) and selected local responsibility areas indicated in the footnotes. Pink tint indicates moderate hazard and red indicates very high hazard (no areas of high hazard predominated for any type of infrastructure in any facility).

	Facility	Well(s)	Flowline(s)	Plant	Interconnect	Source
Independents	Gill Ranch Gas[1, 2]	Not zoned	Not zoned	Not zoned	Not zoned (moderate)	[1]Cal Fire (2007b) [2]Cal Fire (2007c)
	Kirby Hill Gas[3]	Moderate	Moderate	Moderate	Moderate	[3]Cal Fire (2007d)
	Lodi Gas[4, 5]	Not zoned	Not zoned (moderate)	Not zoned	Not zoned (moderate)	[4]Cal Fire (2007e) [5]Cal Fire (2007f)
	Princeton Gas[6]	Not zoned	Not zoned	Not zoned	Not zoned (moderate)	[6]Cal Fire (2007g)
	Wild Goose Gas[7]	Not zoned	Not zoned (moderate)	Not zoned	Not zoned (moderate)	[7]Cal Fire (2007h)
PG&E	Los Medanos Gas	Moderate	Moderate	Moderate	Moderate	
	McDonald Island Gas[4, 8]	Moderate	Moderate	Not zoned	Not zoned (moderate)	[4]Cal Fire (2007e) [8]Cal Fire (2007i)
	Pleasant Creek Gas[9]	Moderate	Moderate	Moderate	Moderate	[9]Cal Fire (2007j)
SoCalGas	Aliso Canyon[10]	Very high	Very high	Very high	Very high	[10]Cal Fire (2011)
	Honor Rancho[10]	Very high	Very high	Very high	Very high	[10]Cal Fire (2011)
	La Goleta Gas[11]	Not zoned	Not zoned	Not zoned	Not zoned	[11]Cal Fire (2007k)
	Playa del Rey[10]	Very high	Very high	Very high	Not Zoned (Very high)	[10]Cal Fire (2011)

The facilities in southern California are in the highest fire hazard severity zones as a group. In contrast, PG&E's facilities are mostly in moderate fire hazard severity zones, and the independent facilities are primarily not in a fire-hazard severity zone. These differences generally correlate to whether wild vegetation exists in the vicinity, and if so, whether it consists of grasslands or vegetation with higher fuel density, such as chaparral or forest.

1.2.3.13 Linkages Between Failure Modes

As shown in Figure 1.0-1, containment of high-pressure gas in UGS relies on an integration of components into a system. As with any system, failure of one component can lead to failure(s) of other components. In the bulleted list below, we detail some examples of modes of failure for wells (Figure 1.2-23) and for reservoirs (Figure 1.2-24) that are coupled and strongly linked. Specific examples of linked failure modes have been documented in the literature (e.g., Evans, 2009; Folga et al., 2016). This list highlights the importance of maintenance and testing of every component in order to ensure integrity of the whole UGS system at each facility.

Loss of Well Integrity:

- **Injection/Withdrawal through Tubing/Packer** – Failure of tubing or packer and tubing is plugged (assumes no surface or subsurface safety valve functioning and in place) – Pressurized gas migration into annular space – Corrosion of production casing causes loss of well integrity (hole) in uncemented or poorly cemented section of production casing – Pressurized storage gas migrated through hole in production casing and into uncemented annular space – Gas migrates upwards in borehole and gas pressure exceeds breakdown pressure of surface casing seat/shoe – Gas migrates around surface casing and then enters lower pressure aquifers and/or breaksout (fractures) as an uncontrolled release at the surface (breach blowout).

- **Injection/Withdrawal through Casing Only (Casing Injection)** – Failure of integrity of the production casing due to corrosion (assumes no surface or subsurface safety valve functioning and in place) – Pressurized gas migration into uncemented or poorly cemented annular space - Gas migrates upwards in borehole and gas pressure exceeds breakdown pressure of surface casing seat/shoe – Gas migrates around surface casing and then enters lower pressure aquifers and/or induced fractures as an uncontrolled release at the surface.

- **Well Work-over or Plugging and Abandoned Operations** – Well is “killed” with heavy brine or mud (assumes wellhead is not configured to work under pressure) to alleviate gas storage pressure – Wellhead is disassembled for installation of blowout preventers (BOPs) – Prior to installation of BOPs, well “kicks” due to under balance of “kill” fluids and there is an immediate uncontrolled release through the well at the surface.

- **Plugging and Abandonment Well Release** – Well has been permanently plugged and abandoned – Subsurface mechanical plug or cement plug(s) fail – Gas migrates out of storage reservoir and enters shallower porous and permeable geologic formations – Gas invasion into shallower oil and gas production or disposal wells and impacts operations or gas invasion into other abandoned or improperly plugged wells - Potentially breaks out at the surface and/or migrates into aquifers.

- **Seismic Activity** – Strong enough earthquake that damages wellbore and allows for uncontrolled release at the surface (assuming no surface or subsurface safety valve functioning and in place).

- **Wellhead Damage** – Damage to wellhead (accidental or intentional) – Severe enough damage to allow for uncontrolled release without ability to shut in well (assuming no surface or subsurface safety valve functioning and in place).

Figure 1.2-23. Linkages between well integrity failure modes.

Loss of Reservoir Integrity (breaches in horizontal or vertical seal containment):

- **Overpressurization of Gas Storage Reservoir** – Injection pressures exceed pressure limits of confining zone/interval – Gas migrates out the storage reservoir into shallower porous and permeable geologic formations – Pathways may include migration to other shallower, producing oil and gas wells, disposal wells, or migration into abandoned or improperly plugged wells – Gas migration could reach the surface or into aquifers.

- **Overfilling of the Gas Storage Reservoir** – Gas storage reservoir is overfilled and exceeds the spill point or geologic trapping mechanism of the formation being utilized for gas storage – Gas migrates out of the storage reservoir and finds pathways into abandoned or improperly plugged wells or other oil and gas producing horizons – Potentially breaks out at the surface or migrates into aquifers.

- **Third-Party Damage to Gas Storage Reservoir** – Artificial penetration into or through the gas storage reservoir by third-party operator during drilling or plugging operations – Uncontrolled release of gas at the third-party wellhead due to overpressurization and/or inadequate well control measures at the surface.

Figure 1.2-24. Linkages between reservoir integrity failure modes.

We present in Figure 1.2-25 a fault tree representation of the first linked scenario in Figure 1.2-23. As shown, fault trees make use of AND and OR gates to graphically depict the linkages of various features, events, and processes (FEPs) in a failure scenario. The likelihood of the top event can be calculated using knowledge of the likelihoods of each of the contributing events and the logic of the AND and OR gates (e.g., Vesely et al., 1981; Oldenburg and Budnitz, 2016).

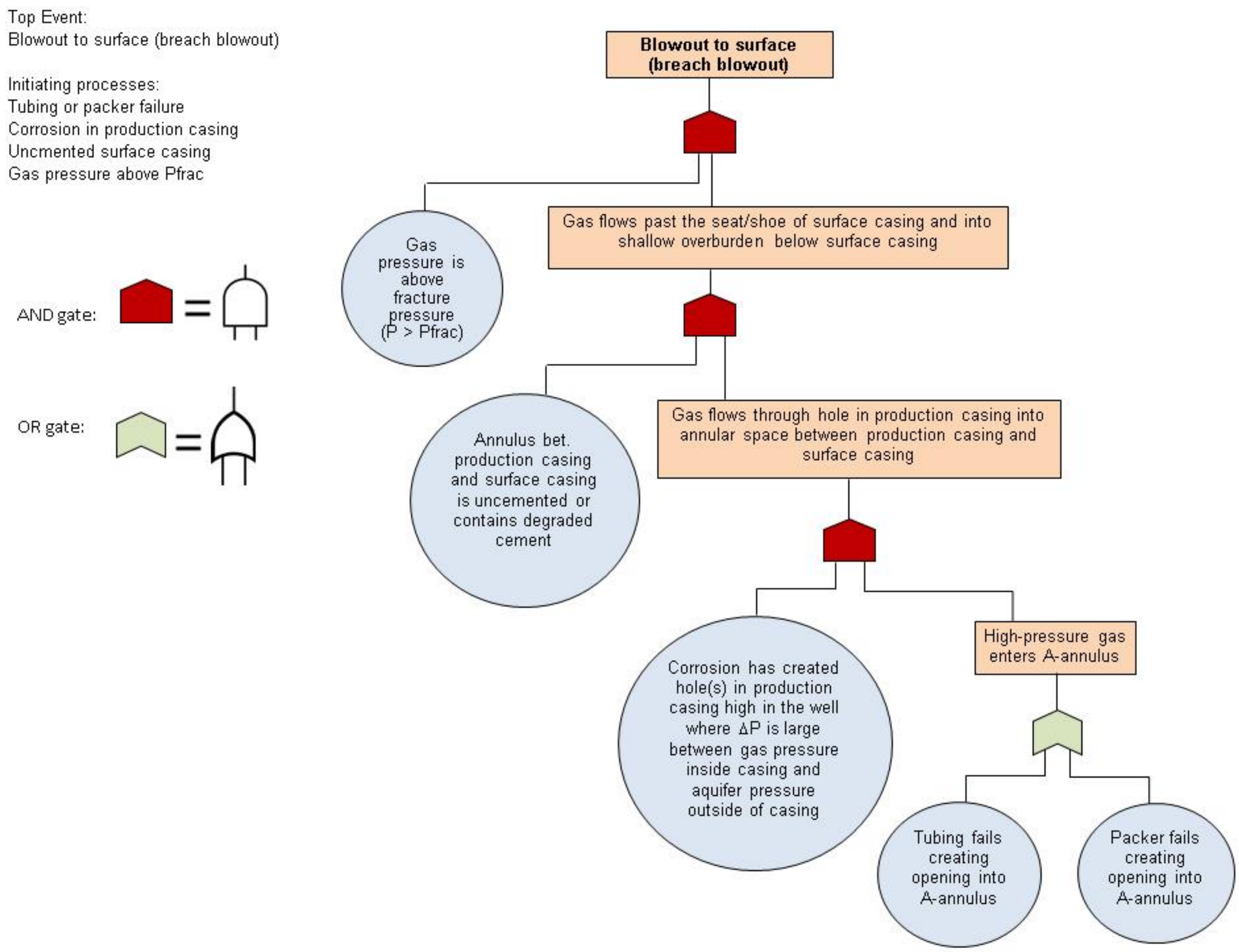


Figure 1.2-25. An example of a fault tree applicable to UGS wells in California depicting the initiating and contributing events to the top event (Blowout to surface) as described by words of the first item in the list of well-integrity failure linkages above.

1.2.4 Likelihood of Failure of UGS

Likelihood of failure can be estimated in various ways. Evans (2009), Folga et al. (2016), Schultz et al. (2017), and Evans and Schultz (2017) have used reported incidents and associated information on cause, field type, location, and mode to develop incident databases (catalogs) from which annual frequency of incidents per UGS facility, or per well, or per year of operation, or per any other combination of operating parameters one wants to use as a basis for frequency can be determined. We refer to the number of incidents in whatever classification(s) as the numerator, and the number of facilities, or number of wells, etc. as the denominator. Regardless of the details, the essence of the approach is to estimate annual frequency from the historical records of incidents. Annual frequency can be converted to time to event by simply inverting the frequency. The main goal of this section is to discuss the estimate of the likelihood of incidents at California UGS facilities, which will require sampling from the various incident databases and estimates from the literature. We begin by describing historical records of UGS failures to estimate time-to-event. Additional approaches to estimating failure likelihood will also be discussed.

1.2.4.1 History of UGS Loss-of-containment and Other Failures

1.2.4.1.1 Subsurface

Very significant and useful compilations of UGS incidents have been carried out by Evans (2009), Folga et al. (2016), Schultz et al. (2017), and Evans and Schultz (2017). Evans (2009) catalogued worldwide incidents for UGS for the various kinds of storage reservoirs, namely depleted hydrocarbon reservoir (DHR), Aquifer, Salt Cavern, and other subsurface storage types. Table 1.2-7 presents only the California incidents as a subset of the larger set of worldwide incidents catalogued by Evans (2009). All of the California UGS facilities are in depleted hydrocarbon reservoirs (DHR), although one reservoir interval at the DHR Kirby Hill facility is classified as aquifer storage (U.S. EIA, 2016), which may have led Evans (2009) to classify it as an aquifer storage facility. Every one of the incidents in Table 1.2-7 involves loss-of-containment (LOC) except apparently numbers (9) and (11), without evaluation or ranking by severity.

Table 1.2-7. California UGS incidents extracted from the list of worldwide UGS incidents compiled by Evans (2009). Note that Pleasant Creek was listed by Evans as an aquifer storage reservoir storage site, but we include it here as a DHR site. The numbers in parentheses in Column 6 correspond to the contributory processes (causes) enumerated in Table 1.2-9. The dark pink incidents are at facilities that are currently active UGS sites in California, while the light pink incidents are no longer active UGS facilities. The white rows are incidents that did not report loss-of-containment as a consequence of the incident. Note that the table says Montebello closed in 2003, but in fact injection and production continued until 2016 (see Section 1.1.3 of this report).

	Depleted Oil/Gasfield Storage					
	Facility	**Operator**	**Product**	**Date**	**Description of event/fatalities/injuries**	**Reported cause/comment (bracketed numbers = mechanism in Figure 5)**
Incidents involving casualties/evacuations						
1	Montebello, LA California, USA	SoCal	Gas	1950s-1980s	Storage gas lost over extended period. In 1980 found within housing estate above field - led to evacuation of families on many occasions	Storage gas migrated via old, poorly completed wells and possibly faults. Injection pressure higher than original oilfield pressure, causing fracture and damage to old wells. Injection ceased 1986, facility closed 2003. Improperly plugged wells requied re-abandonment (1, 5, 14)
Incidents where no casualties involved but financial or property loss or closure occurred						
2	Playa del Rey, LA, California, USA	SoCal	Gas	April 2003	25 minute release of gas with a fine mist of oil	Valve in compressor unit broke (2)
3	Castaic Hills & Honor Rancho, California, USA	SoCal	Gas	1975-present?	Gas migration from Castaic reservoir to adjacent fields & thence to surface	Gas migrated laterally to shallower Honor Rancho & Tapia structures, via faults and thence to surface, killing oak trees - affected oil production in nearby producing wells (1, 4, 12, 13, 14)
4	Playa del Rey, LA, California, USA	SoCal	Gas	1940s-present day	Migration of large amounts of stored gas	Stored gas has migrated from PDR structure into Venice structure from earliest days, connection between structures, some fault & well related (1, 5, 12, 14)
5	McDonald Island, Stockton, California, USA	Pacific Gas & Electric Co.	Gas	Oct 1993	Explosion, causing US $2 million damage	Explosion in moisture extraction (gas conditioning) plant (2)
6	McDonald Island, Stockton, California, USA	Pacific Gas & Electric Co.	Gas	1974	Explosion, fire burned for 19 days, 0.42 Mcm gas consumed	Not available (18)
7	East Whittier, California, USA	SoCal	Gas	1970s	Gas migrated from original injection site	Injected gas produced by other company, facility eventually closed in 2003 (4, 5, 12).
8	El Segundo, California	Not available	Gas and propane	Early 1970s	Gas migration -threatening housing development	Gas migration from reservoir to surface along fault planes. Facility initially shut in (pre 1993) but now abandoned for safety due to new housing (4, 5, 12, 13)
9	California, USA	Not available	Gas	Not available	Storage well damaged - crushed	Storage well damaged during earthquake (1, 17)
10	California, USA	Not available	Gas	Not available	Storage well damaged - casing shoe leak	Well inadvertently sidetracked during repair of casing shoe leak (1, 11)
11	California, USA	Not available	Gas	Not available	Corrosion of storage well casing	Well inadvertently sidetracked during repair of corroded casing (1, 11)
12	Pleasant Creek, California, USA	Not available	Gas	1972-1976	Soil gas surveys detect gas over storage area	Gas migrating up out of reservoir. Poor seal? (4, 12, 13)

As shown in Table 1.2-7, 12 incidents occurred in California out of 228 total incidents shown in Evans' original worldwide UGS incident table (Evans, 2009, Figure 6), but there were only 27 DHR incidents worldwide, which means California had almost half (12/27) of the reported worldwide DHR UGS incidents. This fact is discussed by Evans (2009) as possibly being explained by California's reliance on old wells and relatively lax U.S. and California regulation relative to worldwide UGS standards. It is important to note that only ten incidents in Table 1.2-7 involved reported LOC, and only eight LOC incidents were reported at facilities that are still being used for UGS in California. Nevertheless, with California having eight of the total 27 DHR LOC incidents, California apparently has a disproportionate number of LOC incidents relative to the worldwide average.

Among the 27 worldwide DHR incidents reported by Evans (2009), three are related to valves and other surface operations. Two had unknown causes. Therefore, 22/27 (81%) of the California LOC incidents are documented to be related to subsurface integrity (casing, seal, well control, etc.) failure. This proclivity toward incidents related to subsurface integrity also applies to aquifer storage in the data of Evans (2009), who reports 17/24 (71%) of the incidents are subsurface-integrity related.

1.2.4.1.2 Surface

Folga et al. (2016) updated and augmented the tables of Evans (2009), parts of which we presented in Table 1.2-7, by adding incidents taken from the PHMSA database. The comprehensive Folga et al. (2016) table that we have filtered to show only California UGS incidents is presented as Table 1.2-8. Note that there are only six facilities with incidents listed in the table that are still storing gas (Los Medanos, McDonald Island, Playa del Rey, Aliso Canyon, Honor Rancho, and Wild Goose). A total of 11 of the 13 incidents at sites still storing gas involve LOC. Approximately one-half of the LOC incidents in California were due to wells (7/16 incidents) and one-half (6/16) of the incidents in Table 1.2-8 were related to surface infrastructure.

Table 1.2-8. California-only portion of the table from Folga et al. (2016) that combines the Evans (2009) compilation with incidents from the PHMSA database to create a comprehensive list of 16 California UGS incidents. Note that El Segundo, East Whittier, and Montebello no longer store gas, leaving 13 incidents at existing UGS facilities. Note further that the first Aliso Canyon incident in the table, and the first Honor Rancho incident, did not involve LOC, leaving 11 LOC incidents. The failure mechanism ID's in column 8 are presented in Table 1.2-9.

Field Name	County Name	State	Current Operator	Date	Impacts	Reported Cause	Failure Mechanism ID	Source
Los Medanos	Contra Costa	CA	Pacific Gas and Electric Company	5/25/2011	No service has been lost.	During a scheduled hydrotest job, the valve stem on an inlet fire valve to a regulator station at 2445 Garcia Avenue in Mountain View broke at 1,745 hours. The valve was being operated to release water from the line. The valve was broken in the partially open position causing gas to escape.	2, 11	PHMSA
McDonald	San Joaquin	CA	Pacific Gas and Electric Company	10/1/1993	Explosion, causing $2 million damage.	Explosion in moisture extraction (gas conditioning) plant.	2	Evans and Chadwick, 2009
McDonald	San Joaquin	CA	Pacific Gas and Electric Company	1974	Explosion, fire burned for 19 days, 15 Mcf consumed.	Not available.	18	Evans and Chadwick, 2009
El Segundo	Los Angeles	CA	Standard Oil Company of California	Early 1970s	Gas migration—threatening housing development.	Gas migration from reservoir to surface along fault lines. Facility finally shut in (pre-1993) but now abandoned for safety, due to new housing.	4, 5, 12, 13	Evans and Chadwick, 2009
Playa Del Rey	Los Angeles	CA	Southern California Gas Company	1/6/2013	The soot from the burned gas caused mist damage to neighboring homes, landscaping, and vehicles. Facility is currently shutdown during ongoing investigation and inspection of pipeline facilities.	At the Playa Del Rey underground storage facility, an unintentional and momentary opening of a block valve allowed a release of high-pressure gas into lower-rated pressure piping. This resulted in unplanned release of gas through the relieving valve system and an over-pressure of certain station piping. The gas emitted through the relief system ignited.	2, 4	PHMSA
Aliso Canyon	Los Angeles	CA	Southern California Gas Company	1/17/1994	Storage well damaged—crushed. Supply of gas from Aliso Canyon interrupted for five days.	Storage well damaged during 1994 Northridge Earthquake.	1, 17	Evans and Chadwick, 2009
Aliso Canyon	Los Angeles	CA	Southern California Gas Company	2008	High-pressure gas could migrate to the surface in a manner of hours, according to SoCalGas testimony.	Corrosion of storage well casing. Surface annulus of well Porter 50A had a pressure of over 400 psig.	1, 11	Evans and Chadwick, 2009
Aliso Canyon	Los Angeles	CA	Southern California Gas Company	2013	No evidence of the leaks at the surface or surface casing.	Two wells were found to have leaks in the production casing at depths adjacent to the shallower oil production sands.	1, 11	Evans and Chadwick, 2009
Aliso Canyon	Los Angeles	CA	Southern California Gas Company	2/4/2006	No injuries resulted from this incident. Overpressure was quickly alleviated, and relief valve reset.	A relief valve triggered on an underground storage facility wellhead, spraying petroleum mist on nearby brush and hillside. An investigation of this incident determined that while 400 barrels were being injected into the well, excessive backpressure during flowback occurred, tripping a relief valve, as designed, when pressure exceeded MAOP.	2	PHMSA
East Whittier	East Whittier	CA	Southern California Gas Company	1970s	Gas migrated from original injection site.	Injected gas produced by another company; facility finally closed in 2003.	4, 5, 12	Evans and Chadwick, 2009
Honor Rancho	Los Angeles	CA	Southern California Gas Company	1992	Storage well damaged—casing shoe leak.	Well inadvertently sidetracked during repair of casing shoe leak.	1, 11	Evans and Chadwick, 2009
Honor Rancho	Los Angeles	CA	Southern California Gas Company	1975–2008	Gas migration from Castaic reservoir to adjacent fields and then to surface.	Gas migrated laterally to shallower Honor Rancho and Tapia structures, via faults, and then to surface, killing oak trees—affected oil production in nearby producing wells.	1, 4, 12, 13, 14	Evans and Chadwick, 2009
Montebello	Los Angeles	CA	Southern California Gas Company	1950s–1980s	Storage gas lost over extended period. In 1980, found within housing estate above field—led to evacuation of families on many occasions.	Storage gas migrated via old, poorly completed wells and possibly faults. Injection pressure higher than original oilfield pressure, causing fracture and damage to old wells. Injection ceased 1980; facility closed 2003.	1, 5, 14	Evans and Chadwick, 2009
Playa Del Rey	Los Angeles	CA	Southern California Gas Company	4/1/2003	25 minute release of gas with a fine mist of oil.	Valve in compressor unit broke.	2	Evans and Chadwick, 2009
Playa Del Rey	Los Angeles	CA	Southern California Gas Company	1940s–2008	Migration of large amounts of stored gas.	Stored gas has migrated from PDR structure into Venice structure from earliest days, connection between structures, some fault and well-related.	1, 5, 12, 14	Evans and Chadwick, 2009
Wild Goose	Butte	CA	Wild Goose Storage Inc.	2/28/1999	Not specified.	Company had been operating the pipeline for 6 months at 1,400 psi. Because the operating pressure would be increasing in the near future, the decision was made to block in the wells allowing the pipeline pressure to increase to its maximum working pressure. When the pipeline reached a pressure of 1,580, a leak between two flanges was discovered.	2, 5	PHMSA

Folga et al. (2016) listed the main processes leading to UGS failure and the number of incidents worldwide that have occurred by each process in DHR facilities (non-purple entries) as shown in Table 1.2-9. As shown by comparing the numbers for processes (1) and (2), wells and surface infrastructure, respectively, the aboveground valves, pipes, wellheads, compressors, and other components have been associated with over four times (61) as many incidents as wells (14). Note further in Table 1.2-9 that some incidents involve more than one process, resulting in double-counting in the table. Table 1.2-9 shows that the majority of reported UGS incidents occur above ground (ID = 2), followed by design/construction failure (ID = 4), and well failure, including blowout (ID = 1).

It is apparent that Folga et al. (2016) come to a different conclusion about relative numbers of surface versus subsurface failures than Evans (2009). In particular, the results of Evans (2009) are contradicted by the more recent results in Folga et al. (2016), who note that far more surface-related incidents occur. Two important points are relevant: (1) the change in conclusion about importance of surface incidents arose because Folga et al. (2016) added the PHMSA data which are all surface-related, indicating that reporting, or what data one counts, controls the conclusion; (2) the consequences of surface incidents can be catastrophic (involving deaths) because the effects occur where there can be people present, but they can also be minor because surface failures are often promptly addressed by manual closing of valves or by automatic failsafe systems, or by some other emergency operational procedure.

Table 1.2-9. Contributory processes and worldwide number of DHR incidents attributed to those causes. Note that Folga et al. (2016) included salt cavern processes that are not applicable to California UGS (colored purple in the table to indicate lack of applicability in California).

ID	Main contributory processes attributed to leak/failure mechanism/abandonment of facility	Number of incidents in depleted hydrocarbon reservoir storage
1	well/casing/brine string/plug problems/failure, incl blowout	14
2	above ground infrastructure - valve/pipes/wellhead/compressor/gas detection system	61
3	loss of wellhead pressure or failed pressure test	0
4	design/construction failure - including site characterization, caprock performance, leaching	13
5	operational failure - overpressure/fill reservoir (spillpoint)/aquifer/cavern, operational procedures (human error)	11
6	operational failure - hydrostatic pressure too low, storage reservoir/cavern too shallow	0
7	Operational failure - low pressures, salt creep	0
8	operational failure - leaching (unknown & uncontrolled), cavern communication, roof collapse (salt or overburden)	0
9	caverns/void problems - fractures, creep, high insolubles, collapse/salt wall fall, filling with water (Russia)	0
10	inadvertent intrusion	5
11	during repair/testing/maintenance	6
12	migration from injection footprint/cavern (not due entirely to well problems)	10
13	cap rock - not gas tight/salt thick enough	2
14	cap rock - fractured/faulted, not gas tight	4
15	mine shaft	1
16	wet rockhead/sinkholes	0
17	seismic activity	2
18	not available	7

A great deal of information has been collected on the failure rates of pipelines and related infrastructure from a variety of industrial applications. For example, van Vliet et al. (2011) presented results of failure frequency for on-site aboveground, high pressure natural gas lines at onshore natural gas facilities. Aboveground natural gas lines have flanges that one might consider a greater hazard than straight piping. However, van Vliet et al. (2011) reported that a flange connection can withstand a larger impact and stress than the pipeline it is connected to. Therefore, van Vliet et al. (2011) excluded ruptures of flange connections from their risk calculations. Failure frequencies estimated by van Vliet et al. (2011) are shown in Table 1.2-10.

Table 1.2-10. Failure frequencies and time to event for 1 km pipeline for aboveground high-pressure gas lines (after van Vliet et al., 2011).

Failure category	Failure frequency (per m per yr)	Time to event for 1 km of pipe (yrs)
Rupture (> 1/3 pipe diameter)	6.5×10^{-9}	150,000
Large hole (1/3 diameter)	3.3×10^{-8}	30,000
Small hole (5 mm – 25 mm diameter)	6.7×10^{-8}	15,000
Pin hole (≤ 5 mm diameter)	1.6×10^{-7}	6,250

Vendrig et al. (2003) reported CO_2 pipeline failure rates and corresponding time to event likelihoods as shown in Table 1.2-11. As shown, the Modules 2-4 involving pipelines and compression have low failure rates and time to event estimates from 25 to nearly 3,000 years.

Table 1.2-11. Yearly failure rate summary per module from Vendrig et al. (2003).

Module		Expected failure rate (events per module per year)	Leak every x years
1	CO_2 recovery at source	1.5×10^{-1}	7
2	Converging pipelines	4.6×10^{-3}	217
3	Booster station	4.0×10^{-2}	25
4	10 km pipeline	3.4×10^{-4}	2,941
5	Injection well	1.8×10^{-1}	6

One can compare the estimates of Vendrig et al. (2003) for CO_2 pipelines with the estimates of van Vliet et al. (2011) for natural gas by assuming a 10 km pipeline and an intermediate frequency failure category (a large hole). From Table 1.2-10, we have $1/(3.3 \times 10^{-8}\ m^{-1}\ yr^{-1} \times 10{,}000\ m) = 3{,}030$ yrs as compared to Vendrig et al. (2003), who estimate time to event for 10 km CO_2 pipeline at 2,941 yrs. Because no one would expect a single pipeline to last 3,000 yrs, a more practical measure of the reliability of pipelines might be the translation of the above times to event into a measure such as the length of pipeline that one would need before expecting a failure in a decade. The 3,000 yr time to event estimated here would translate to the expectation of no failures in a decade over 3,000 km of pipeline (1 event/3,000 yrs/10 km = 1 event/10 yrs/3,000 km). Regardless of how it is quantified, it is clear that flowlines have very low failure frequency and long times to event.

As shown in Figure 1.0-1, UGS surface infrastructure comprises a lot more than flowlines, consisting also of compressors, gas processing equipment, turbine and reciprocating generators, valves, etc. And the statistics show that failures of surface infrastructure in general occur approximately four times more often than failures related to wells, as shown in Table 1.2-9. But there is a big difference in what can be done to mitigate and respond to surface infrastructure failure relative to (subsurface) well or reservoir integrity failure. The main difference is that surface ruptures of pipelines or other surface components are readily visible and apparent, so that operators can identify and locate leaks quickly and address them by isolating the failed component(s) and closing valves, and then blowing down the affected system. Because leaks in surface infrastructure can be found and addressed quickly, the total amount of gas released tends to be small, resulting in small consequences. On the other hand, the presence of workers and potentially the public in the surface environment can also increase consequences in the event of fire or explosion associated with loss-of-containment. In contrast, loss-of-containment in the well environment, e.g., through a casing breach at depth, is difficult to detect and repair, and total LOC amounts can be large with no impact to people. When such leakage goes on undetected, the problem can grow and become worse until one has a blowout which can sometimes be difficult to kill, as demonstrated by the 2015 Aliso Canyon incident. This points to the need for effective monitoring.

1.2.4.1.3 Estimates of Likelihood Based on Recorded LOC Incidents

Based on the compilation of Folga et al. (2016), we can estimate the likelihood of LOC failures in California a few different ways. We show in Table 1.2-12 the 12 current California UGS facilities ranked by working-gas capacity and showing years of operation and number of reported LOC incidents extracted from Folga et al. (2016). From this information, we can estimate likelihood of LOC incidents in terms of incidents per year, time to incident, and probability of incident.

Before presenting any results from this analysis, several caveats are needed. First, there are only 12 incidents in Table 1.2-12, and five of the UGS facilities have no recorded incidents at all, making calculation of time to event questionable for those facilities. Nevertheless, failure frequencies are needed to evaluate risk, and these data (and more recent additions; see below) are all that we have in the public domain to use. Second, we note that failure rates may not be constant with time and in fact may increase as facilities age. Therefore, the estimated failure frequencies below may be lower than expected in the future. Finally, note also that only seven of the 12 UGS facilities have reported LOC incidents in the data presented by Folga et al. (2016) that are used here and yet, consistent with the practice of Evans (2008) and Folga et al. (2016), average rates of failure are calculated over all facilities.

The first-order conclusion from this exercise is that the overall likelihood of LOC incidents is 12 incidents/434 facility-yrs = 0.028 incidents/facility-yr or 0.33 incidents/yr at any of the 12 facilities statewide. This corresponds to a time to event of 36 yrs for any given facility on average, and 3.0 yrs (36/12) for all facilities statewide. This can be compared with the frequency estimated by summing the individual likelihoods for all 12 facilities, which comes to 0.278 incidents/yr (or 0.023 incidents/facility-yr), which corresponds to a statewide time to event of 3.6 yrs. The reason the likelihoods of statewide LOC incidents differ (0.33 incidents/yr vs. 0.278 incidents/yr) for these two calculation approaches is that different facilities operated for different periods of time, and this is not accounted for in the former approach.

Second-order conclusions can be drawn for the individual facilities. For example, the time to event for LOC incidents at Aliso Canyon is 14 yrs, whereas the time to event for

Honor Rancho LOC incidents is 41 yrs, and other facilities with reported LOC incidents fall somewhere in between. Aliso Canyon, McDonald Island, and Playa del Rey have more reported LOC incidents (2-3) than any of the other sites. It is important to note that Aliso Canyon and McDonald Island store the most gas of all of the sites. Using a Bcf-weighted likelihood measure (last column in the table in Table 1.2-12), we see that the per Bcf-yr likelihoods of LOC incidents are the lowest for McDonald Island and Aliso Canyon because they have large working gas capacities (store a lot of gas). Playa del Rey has the highest likelihood of LOC incidents using the Bcf-weighted approach because it has three reported incidents and only stores 2.4 Bcf, the second smallest UGS capacity in California. Breaking down the likelihoods for depleted oil reservoirs and depleted gas reservoirs shows approximately equal average likelihoods for LOC failure in oil reservoirs (0.13 LOC incidents/yr) versus average likelihood for LOC failure in gas reservoirs (0.15 LOC incidents/yr).

Table 1.2-12. California UGS facilities (coded red if LOC incident has been recorded, green if not) ranked by capacity showing number of LOC incidents and four different measures of likelihood: (1) LOC incidents/yr, (2) time to event (yrs), (3) likelihood per yr, and (4) incidents per capacity-weighted yr in units of per Bcf-yr).

Field name	working gas capacity (Bcf)	depleted oil (O) or depleted gas (G)	year established	years of operation (until 2016 to match Folga et al.)	capacity-weighted years of opn (Bcf-yrs)	number of distinct LOC incidents from Evans (2009) and Folga et al. (2016)	LOC incidents/year of operation	time to event, t (yrs)	Likelihood, P = 1/(1+t) per year	incidents /capacity-weighted years (per bcf-yr)
Aliso Canyon	86.0	O	1973	43	3698	3	6.98E-02	1.4E+01	6.5E-02	8.11E-04
McDonald Island	82.0	G	1976	40	3280	2	5.00E-02	2.0E+01	4.8E-02	6.10E-04
Wild Goose	75.0	G	1997	19	1425	1	5.26E-02	1.9E+01	5.0E-02	7.02E-04
Lodi	29.5	G	2001	15	443	0	0.00E+00	1.0E+06	1.0E-06	0.00E+00
Honor Rancho	24.2	O	1975	41	992	1	2.44E-02	4.1E+01	2.4E-02	1.01E-03
Gill Ranch	20.0	G	2010	6	120	0	0.00E+00	1.0E+06	1.0E-06	0.00E+00
La Goleta	19.7	G	1941	75	1478	0	0.00E+00	1.0E+06	1.0E-06	0.00E+00
Los Medanos	18.0	G	1979	37	666	1	2.70E-02	3.7E+01	2.6E-02	1.50E-03
Kirby Hills	15.0	G	1975	41	615	0	0.00E+00	1.0E+06	1.0E-06	0.00E+00
Princeton	11.0	G	2010	6	66	0	0.00E+00	1.0E+06	1.0E-06	0.00E+00
Playa del Rey	2.4	O	1942	74	178	3	4.05E-02	2.5E+01	3.9E-02	1.69E-02
Pleasant Creek	2.3	G	1979	37	85	1	2.70E-02	3.7E+01	2.6E-02	1.18E-02
Totals:	385.1			434	13045	12	2.91E-01		0.278	

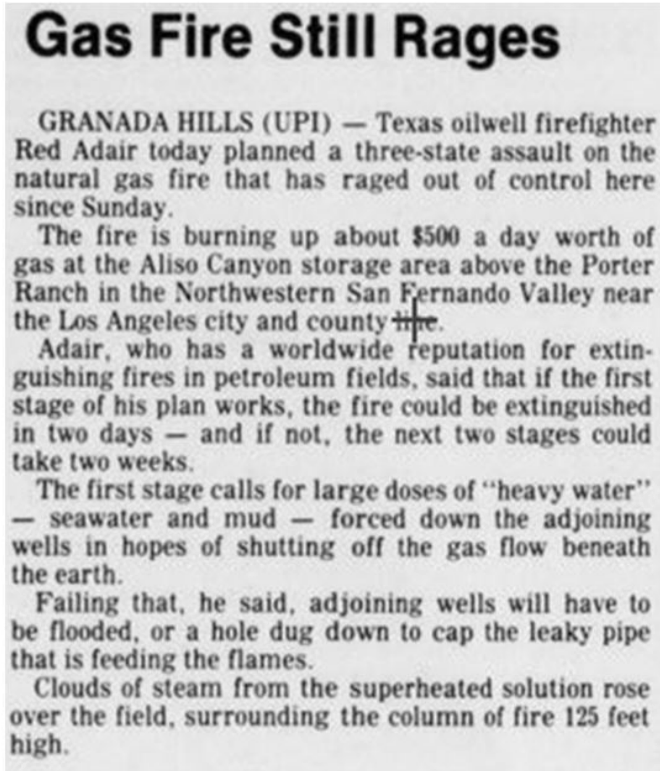
Note that we chose to base the above analysis entirely on the data of Evans (2009) and Folga et al. (2016), and that we did not include Montebello in the analysis. There are three significant points to mention related to these choices, two of which we will address below to improve the incident likelihood estimate.

First, we did not include Montebello in Table 1.2-12 despite the fact that its official cessation of operations was December 31, 2016, placing it within the time period of this study.

The reason we neglected it is that its operational history since 1997 is questionable (see Appendix 2-4 in Chapter 2) making it difficult to obtain information on it for the study period. In addition, it is not possible to determine a time frame for incident occurrence because Montebello has a long history of leakage that is not divided into distinct incidents in the database but rather lumped as a single entry. Nevertheless, the fact is that natural gas from the Montebello UGS facility leaked through abandoned wells into homes as described in Tables 1.2-7 and 1.2-8, leading to evacuations in the early 1980s and tearing down of homes to re-abandon wells properly (Chilingar and Endres, 2005). In short, while we cannot easily include incidents at Montebello in the simple analysis here, we point out that the Montebello UGS facility sustained serious LOC incidents due to well integrity failure, and these occurrences should be informally factored into the estimates of likelihood of LOC incidents due to well integrity failure.

Second, neither Evans (2009) nor Folga et al. (2016) included the 1975 Aliso Canyon incident, which consisted of an ignited gas blowout caused by sand production and failure of an elbow at the wellhead due to erosion by the sand (Hauser and Guerard, 1993). This incident is described in the newspaper article reproduced in Figure 1.2-26. We have not found additional information or details about this incident, but we have added it in to the number of LOC incidents involving well integrity failure in our updated calculation of incident likelihood that immediately follows.

Third, the 2015 Aliso Canyon incident was not in Evans (2009) (pre-dated the incident) nor in Folga et al. (2016) (relied on Evans, 2009). We have also included this incident in the updated incident likelihood estimate that immediately follows.



Gas Fire Still Rages

GRANADA HILLS (UPI) — Texas oilwell firefighter Red Adair today planned a three-state assault on the natural gas fire that has raged out of control here since Sunday.

The fire is burning up about $500 a day worth of gas at the Aliso Canyon storage area above the Porter Ranch in the Northwestern San Fernando Valley near the Los Angeles city and county line.

Adair, who has a worldwide reputation for extinguishing fires in petroleum fields, said that if the first stage of his plan works, the fire could be extinguished in two days — and if not, the next two stages could take two weeks.

The first stage calls for large doses of "heavy water" — seawater and mud — forced down the adjoining wells in hopes of shutting off the gas flow beneath the earth.

Failing that, he said, adjoining wells will have to be flooded, or a hole dug down to cap the leaky pipe that is feeding the flames.

Clouds of steam from the superheated solution rose over the field, surrounding the column of fire 125 feet high.

Figure 1.2-26. Desert Sun newspaper article from January 21, 1975 describing the 1975 Aliso Canyon incident.

If we add in the 1975 and 2015 Aliso Canyon incidents to the numbers in Table 1.2-12, we would have 14 total LOC incidents, making the frequency 14 incidents/434 facility-yr = 0.032 incidents/facility-yr or 0.39 incidents/yr for the 12 facilities statewide. The corresponding updated time to event is 2.6 yrs compared to the prior estimate of 3 yrs. For Aliso Canyon alone, the incident frequency is 5 incidents/43 yr = 0.116 incidents/yr, or a time to incident of 8.6 yrs. The depleted oil reservoir UGS LOC incident likelihood when we include the 1975 and 2015 Aliso Canyon incidents is equal to 0.17 LOC incidents/yr versus 0.13 LOC incidents/yr without these additional two incidents.

1.2.4.2 Comparison with Prior Estimates of Likelihood for Worldwide UGS

Folga et al. (2016) calculated the overall likelihood of UGS incidents as between 8.4×10^{-4} and 6.0×10^{-3} per facility yr (see Table 4.2-5 in Folga et al. (2016)). The estimates of Folga et al. (2016) include salt cavern, aquifer, and DHR storage types and are calculated based on total worldwide reported incidents, not just for California and not just for LOC. In addition, the Folga et al. (2016) table (Folga et al. (2016), Table 4.2-5) shows that salt cavern incident likelihoods are higher than for DHR. As such, the Folga et al. (2016) estimates are conservative (i.e., they err on the high side) relative to DHR LOC incidents. Despite the expected higher values of Folga et al. (2016) relative to actual, the California-only DHR LOC incident likelihood as summarized in Figure 1.2-13 is 3.5 times higher at 0.021 incidents per facility-yr compared to the Folga et al. (2016) upper value of 6.0×10^{-3} incidents per facility-yr. The original Evans (2009) and the recent update by Evans and Schultz (2017) also report much higher likelihood of LOC incidents for California UGS facilities relative to the rest of the world.

Whether or not the failure rate for California UGS facilities is actually higher than the rest of the U.S. and world is an open question. The reason one cannot conclude that California LOC incidents are higher than the rest of the world is that the statistics depend on the reporting that has populated the databases. It is possible that California has reported incidents more completely than is typical, resulting in more incidents in the database. Another possibility is that California's larger individual facilities may store and handle a lot more gas than other facilities in other regions, resulting in more vulnerability to LOC incidents. The U.S. stores approximately 1/3 of all gas stored worldwide (IEAGHG, 2006), and California stores (and handles) a significant amount of gas (~385 Bcf working gas capacity).

1.2.5 Recent Updates to the Incident Database

1.2.5.1 Global Update

During the course of this study, the Evans (2009) database was updated by Evans and Schultz (2017) and is still undergoing quality control and validation at the time of writing this section (Evans, pers commun.). Nevertheless, Evans and Schultz have generously shared some preliminary results of querying their updated database for use in this report. The main improvements that Evans and Schultz (2017) have made in the database were to (1) add to the database those incidents that Evans and Schultz have found reported in publicly available documents since 2008; (2) add to the database older incidents that were not included in the 2008 database because they were not known at the time (typically not then electronically searchable, but now electronically searchable), and (3) add in the reported or estimated severity of the incident, which adopted a 1-8 scale in an attempt to undo some of the range compression noted in scales limited to 1-5 and which are commonly used in risk-management approaches such as risk matrices.

In total, the updated Evans and Schultz (2017) database contains 1,023 recorded incidents (up from 228 incidents in the 2008 database) from around the world involving underground fuel storage in all of its forms (aquifer, depleted hydrocarbon reservoir, salt cavern, mined opening). The database contains 528 incidents recorded for natural gas (methane) in DHR storage facilities. Of these, 166 involved subsurface well integrity, 69 involved subsurface storage integrity, six were due to direct human error, 286 involved aboveground infrastructure, and one was unknown. Globally, 235 incidents were subsurface-related and 282 were surface-related, and seven were unspecified. From these data, we conclude that globally surface incidents slightly exceed subsurface incidents

(286/235 = 1.2). Ignition and/or explosion occurred in 64 of the incidents, with six fatalities, 23 injuries, and 11,372 evacuees. To see how these kinds of consequences map to severity, we present in Table 1.2-13 the eight degrees of severity defined by Evans and Schultz (2017). While we do not endorse every detail of the Evans and Schultz (2017) severity descriptions, we support the idea of ranking incidents by severity, and use their table for illustrative purposes in the discussion below.

Table 1.2-13. Evans and Schultz (2017) severity categories.

Severity	Category	Description
1	*Insignificant/nuisance*	operational issues that were easily rectified or repaired, not involving leakage of product fire/explosion/blowout, injury, evacuees, fatalities or leading to financial losses
2	*Minor/ disruptive*	issues including minor/small leakages/surface release, cavern instabilities that were rectified or repaired, vapour flash, but no real financial loss, fire/explosion/blowout, injury, evacuees or fatalities
3	*Moderate (1)*	issues including substantial losses through subsurface leakages, but not involving surface release, leading to financial losses, but no fire/explosion/blowout, injury, evacuees or fatalities
4	*Moderate (2)*	issues including substantial operating problems (including shut-down, closure of caverns &/or loss of roof salt) or substantial losses through subsurface leakages, involving surface release, gas in observation or water wells, or pipeline leakages, leading to financial losses, ± fire/explosion/blowout, but no injury, evacuees or fatalities
5	*Significant*	issues including significant leakages/losses and surface release, fire/explosion/blowout leading to financial losses, minor numbers of injured/injuries (1–5), but no evacuees, fatalities or serious property damage
6	*Serious*	issues mainly involving significant surface release, fire/explosion/blowout, greater number of injured/serious injury (5–10), evacuees (<50) and/or serious property damage/financial losses but no fatalities
7	*Major*	issues mainly involving large-scale surface release through well or surface pipelines, ± fire/ explosion/blowout, high numbers of evacuees (50–500), large number of injured/serious injury (10–15) and/or significant property damage/financial losses, but no fatalities
8	*Catastrophic*	issues mainly involving devastating surface release at facility through well or surface pipelines, fire/explosion/blowout, cratering, fatalities, high number of injured (>15) and/or evacuees (>500) and major property damage/financial losses

A large number of new incidents (229) relative to the Evans (2009) database were added to the PHMSA database (and that of Evans and Schultz database) as a result of the CPUC directive of January 26, 2016 to UGS operators in California to inspect their facilities for leaks. The results of this directive are shown in Table 1.2-14 as compiled by Evans and Schultz (2017). The vast majority of the incidents reported are classified as minor nonhazardous and easily remediated. We note the classifications in Table 1.2-14 are not those of Evans and Schultz (2017) as shown in Table 1.2-13, but rather those of theCPUC, who uses the following definitions for severity indicated by Grade 1 – 3:

> *A "Grade 1 leak" is a leak that represents an existing or probable hazard to persons or property and requiring prompt action, immediate repair, or continuous action until the conditions are no longer hazardous.*
>
> *A "Grade 2 leak" is a leak that is recognized as being not hazardous at the time of detection but justifies scheduled repair based on the potential for creating a future hazard.*
>
> *A "Grade 3 leak" is a leak that is not hazardous at the time of detection and can reasonably be expected to remain not hazardous.*

(Source: docs.cpuc.ca.gov/PublishedDocs/Published/G000/M163/K327/163327660.docx accessed 7/18/17). As such, the severity of the 229 incidents as described in column 5 (SED Classification) of Table 1.2-14 would all fall into the Severity 1-2 range, except for the Wild Goose (surface) and McDonald Island (surface and subsurface) LOC events, which may be Severity 3-4 by the new Evans and Schultz (2017) scale.

Table 1.2-14. Summary of results of the CPUC directive for leak detection in California (from Evans and Schultz, 2017).

Facility	Operator	Leaks Found	Leaks Repaired	SED Classification	Location of Leak	Remedial Actions
Aliso Canyon	SoCalGas	66	66	Minor non-hazardous	Above ground	Tightening, adjustment, lubrication or replacement of parts or piping.
La Goleta	SoCalGas	17	17	Minor non-hazardous	Above ground	Tightening, adjustment, lubrication or replacement of parts or piping.
Honor Rancho	SoCalGas	1	1	Non minor non-hazardous	Above ground	Tightening, adjustment, lubrication or replacement of parts or piping.
		13	13	Minor non-hazardous	Above ground	Tightening, adjustment, lubrication or replacement of parts or piping.
Playa Del Rey	SoCalGas	3	3	Minor non-hazardous	Above ground	Tightening, adjustment, lubrication or replacement of parts or piping.
Montebello	SoCalGas	6	6	Minor non-hazardous	Above ground	Tightening, adjustment, lubrication or replacement of parts or piping.
Wild Goose Storage	Wild Goose Storage Inc.	27	21	3 (High priority) 8 (Medium priority) 16 (Low priority)	All above ground	21 leaks repaired and corrective actions begun to address remaining six leaks but final repair had not been completed by March 2016.
Lodi	Lodi Gas Storage LLC	0	0	Not applicable	Not applicable	Not applicable
Central Valley Gas Storage	Central Valley Gas Storage LLC	2	2	Grade 3	Above ground	Repaired on 2/4/16 and 2/5/16
Gill Ranch Storage	Gill Ranch Storage LLC	10	1	1 (Grade 2) 9 (Grade 3)	Above ground	Grade 2 leak was repaired 2/9/16. Grade 3 leaks were scheduled to be repaired within 60 days.
Los Medanos	PG&E	23	23	8 (Grade 1) 18 (Grade 2) 58 (Grade 3)	Above ground	Seven leaks were awaiting remedial action. PG&E completed remediation of 17 leaks of the 24 leaks as of 3/6/2016. The remaining 2 Grade 1 leaks had blown down and were not leaking at time of report, but required assistance from third party vendor to complete the repair.
Pleasant Creek	PG&E	29	29		Above ground	
McDonald Island	PG&E	32	25		23 (Above ground) 1 (Below ground)	
Totals		229				

1.2.5.2 Update to California Incidents

To update our analysis of the frequency and location of occurrence (surface or subsurface) of California UGS incidents that were based on the Evans (2009) and Folga et al. (2016) databases as presented above, we requested that Dr. Evans query the database to (1) count all of the California UGS incidents in the new database that occurred up until December 31, 2015, and (2) count all of the incidents occurring between January 1, 2006, and December 31, 2015, the nominal time period for UGS analysis in this report. These do not therefore contain those reported incidents arising from the CPUC directive of January 26, 2016. As shown in Table 1.2-15, a total of 105 incidents are in the database for California, of which 46 are Severity Level 4 ("Moderate(2)") and 42 are Severity Level 2 ("minor, disruptive"). Within our study period from January 1, 2006, until December 31, 2015, Table 1.2-16 shows that the database query for incidents at California UGS facilities nets 63 incidents, of which 39 are Severity Level 4, and 20 are severity Level 2. Note that incidents involving well integrity are by far the most common problems reported, and surface incidents are far outnumbered by subsurface incidents (5/57 = 0.09) in the study period. This contrasts with the global incidence surface to subsurface ratio of (286/235 = 1.2) discussed above, which implies either that California well and caprock/subsurface integrity failures are much more common than globally (many more subsurface incidents) or that California surface infrastructure is much less prone to incidents, which seems very unlikely. The single Severity Level 8 result for both queries is the Aliso Canyon SS-25 well blowout incident. These data shown in Tables 1.2-11 and 1.2-12 are plotted in the pie charts of Figures 1.2-26 and 1.2-27. We note that there are 57 total Severity 4 or higher incidents over all time (Table 1.2-15) and 41 total Severity 4 or higher incidents during the study period (Table 1.2-16).

Table 1.2-15. Evans and Schultz (2017) database hits for California incidents in UGS up to December 31, 2015.

		Severity								
Number	**Mechanism**	***1***	***2***	***3***	***4***	***5***	***6***	***7***	***8***	***Total***
84	***Well Integrity***	0	36	1	42	0	1	3	1	84
1	***Operations/Human error***	0	0	0	1	0	0	0	0	1
5	***Caprock/Subsurface Integrity***	0	0	3	2	0	0	0	0	5
15	***Above ground infrastructure***	2	6	0	1	5	1	0	0	15
0	***Above ground infrastructure/operational***	0	0	0	0	0	0	0	0	0
105	***All***	2	42	4	46	5	2	3	1	105

Table 1.2-16. Evans and Schultz (2017) database hits for California incidents in UGS for the period January 1, 2006 up to December 31, 2015.

		Severity								
Number	Mechanism	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*Total*
57	*Well Integrity*	0	17	1	38	0	0	0	1	57
1	*Operations/Human error*	0	0	0	1	0	0	0	0	1
0	*Caprock/Subsurface Integrity*	0	0	0	0	0	0	0	0	0
5	*Above ground infrastructure*	1	3	0	0	1	0	0	0	5
0	*Above ground infrastructure/operational*	0	0	0	0	0	0	0	0	0
63	*All*	1	20	1	39	1	0	0	1	63

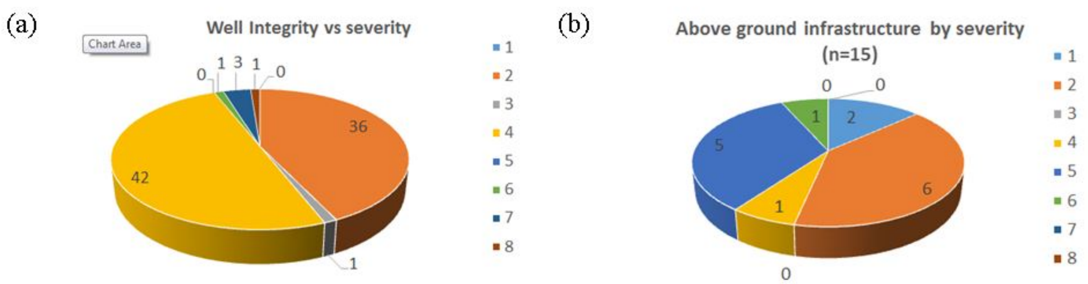


Figure 1.2-27. Counts of UGS incidents by severity up until December 31, 2015 in the updated database of Evans and Schultz (2017).

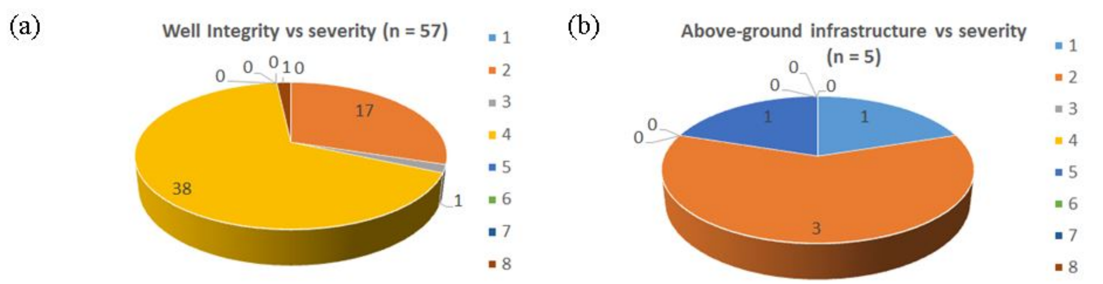


Figure 1.2-28. Counts of UGS incidents by severity for the study period January 1, 2006 until December 31, 2015 in the updated database of Evans and Schultz (2017).

If we consider a threshold of Severity Level 4, which would include incidents that disrupted operation and therefore disrupted reliability of the facility, we count 57 incidents overall and 41 incidents in the project study period. The 57 overall count of California incidents is more than five times the previous count (11) based on the Evans (2009) and Folga et al. (2016) databases (see Table 1.2-8). The quintupling of incidents since 2008 is not likely representative of an increase in frequency of incidents, but rather is more likely an artifact of reporting. For example, the additional 229 California incidents reported in 2016 under the CPUC directive include approximately 10 incidents from the McDonald Island and Wild Goose facilities (Table 1.2-14). Based on the current reporting as recorded in the Evans and Schultz (2017) database as shown in Figure 1.2-28, we estimate the frequency of significant failures (Severity 4 or larger) during the study period by dividing the 41 reported significant incidents by 120 facility years to obtain 0.342 incidents/facility-yr. If there are 12 facilities, we can expect, based on these data, 4.1 incidents every year from some facility somewhere in California. And we can expect that the most likely incidents will be related to well integrity. We note that Severity 4 LOC incidents involve no injuries, evacuees, or fatalities.

1.2.6 Human and Organizational Factors

Humans are widely cited as an important cause of UGS incidents by Evans (2009) and Schultz et al. (2017), whereas human factors as a cause of incidents are not emphasized by Folga et al. (2016). Evans and Schultz (2017) note that operational errors and human errors are often difficult to differentiate, as many operational occurrences result from some sort of human error.

The recognition and analysis of human and organizational factors (HOFs) in risk analysis in the oil and gas industry is growing. Reviews and analysis examples are available in the literature. For example, Tabibzadeh and Meshkati (2014) use the 2010 Gulf of Mexico Macondo well as motivation for the need for consideration of HOFs in deep off-shore oil and gas operations, and present a framework for doing so. In a subsequent paper addressing the Aliso Canyon SS-25 well, Tabibzadeh et al. (in press) utilize Rasmussen's AcciMap organizational principle (Rasmussen, 1997) to describe graphically a hierarchy of contributing factors at Aliso Canyon that led to the SS-25 blowout. HOFs are very significant causes of UGS incidents, and we discuss the need for increased training of UGS staff and emphasis on training for off-normal incidents as a way of addressing HOF in Section 1.6.

In addition to the acts of omission or commission that responsible management, operators, engineers, field technicians, and subcontractors in various areas of a UGS facility may carry out inadvertently, there can also be nefarious human factors. In particular, the threats of terrorism, vandalism, violence, or property destruction by internal or external individuals or groups cannot be ignored. Bajpai and Gupta (2007) provide an excellent summary of this threat and its mitigation for oil and gas infrastructure, an analysis appropriate also for UGS in California. Given the proliferation in terrorism and active shooter incidents over the last 20 years, UGS facilities should continuously evaluate security and minimize the attractiveness of their facilities to individuals and groups intent on harming the facility, its workers, or the general public.

1.2.7 LOC Emission Rates and Dispersion Patterns

The accidental release of high-pressure natural gas at UGS facilities can pose a significant threat to people and property in the vicinity of the leak (see Section 1.4.7). Emission rates can be very large from ruptures in high-pressure pipes, wellheads, compressors, and tanks. For example, during the 2015 Aliso Canyon incident, the SS-25 well emitted natural gas at a rate starting at about 57 tonnes/hr (16 kg/s) in October 2015, and only declined to about 20 tonnes/hr (5.5 kg/s) over the nearly four months until the time the blowout was stopped by means of a relief-well kill (Conley et al., 2016). Flowline ruptures can also produce large flow rates before leaking sections are isolated and the leak is stopped. Blowouts and ruptured lines are typically acute incidents with clear start and end times. At the other end of the spectrum of LOC incidents are chronic and very low-flow-rate leaks from seals and valves that do not create health or safety hazards but that may be significant from a greenhouse gas (GHG) emission standpoint (see Section 1.5). It is often hard to document when these chronic incidents begin because they are hard to detect. For the same reasons, slow chronic leaks may persist for long periods because they are not detected and/or do not create a high-priority safety-related condition.

Regardless of leakage rate, leaking natural gas will disperse following discharge into the atmosphere by the turbulence and air entrainment related to the high-pressure discharge, by local wind and atmospheric instability, and by buoyancy, which can be either positive (leaked gas tends to rise) or negative (leaked gas tends to fall) due to compositional and temperature (expansion cooling) effects on the leaking gas density relative to local air. If ignition occurs, the local wind field can change drastically, and different kinds of flaming and dispersion effects can occur (see next section). The hazards associated with ignition of leaking gas and human exposure (see Section 1.4) to leaking natural gas are controlled by the concentration of the gas at the locations of the people and therefore controlled by gas dispersion.

Leak rates and meteorological data can be combined to model downwind dispersion and estimate concentrations as a function of space and time. We present here an application of this method for demonstration purposes and to estimate the nature of dispersion around California UGS sites in a general sense. The approach we use is based on meteorological data collected from stations that are part of NOAA's Integrated Surface Database (ISD) and located closest to the various underground storage facilities as shown in Appendix 1.B. Using the meteorological data, UGS locations, and an atmospheric dispersion model, we can estimate the extent of flammable natural gas leaking from the UGS facilities for given leakage flow rates. We emphasize that these estimates are approximate because the meteorological data are extrapolated over long distances from the measurement sites to the UGS facilities. Furthermore, although the model is transient, it provides time-averaged values relative to what in reality are rapidly fluctuating concentrations.

The model that we use is NOAA's High-Resolution Rapid Refresh (HRRR) model with real-time 3 km resolution, hourly updated, cloud-resolving, convection-allowing atmospheric dispersion initialized on 3 km grids with 3 km radar assimilation. Radar data are assimilated in the HRRR every 15 min over a 1 hr period adding further detail to that provided by the hourly data assimilation from the 13 km radar-enhanced Rapid Refresh. The model uses the community-based Advanced Research version of the Weather Research and Forecasting (WRF) Model known as the Advanced Research WRF (ARW) and Gridpoint Statistical Interpolation (GSI) analysis system. Modifications have been made to the community ARW model (especially in model physics) and GSI assimilation systems, some based on previous model and assimilation design innovations developed initially with the Rapid Update Cycle (RUC) (https://www.ncdc.noaa.gov/isd, accessed July 26, 2017). Model data for the period 08/15/2015 – 08/15/2016 were archived at National Institute of Standards and Technology (NIST) from the NCEP operational runs (http://nomads.ncep.noaa.gov/). Wind speed and direction at 10 m above ground along with the shortwave incoming radiation and cloud cover were extracted at each storage facility. Additional details on dispersion modeling are provided in Appendix 1.B.

Annual averaged values of dispersion data were computed for each storage facility for four different times of the day; 00-06 (night), 06-12 (morning), 12-18 (afternoon), 18-24 (evening) PST. The averaged wind speed and wind direction data were subsequently combined with plume dispersion models to compute the concentrations downwind of the storage facility. Furthermore, we use a unit flow rate (1 kg/s) as point source(s) from well(s) for the dispersion calculation and then normalize the resulting concentration field by the actual overall facility leak rate. If the leak rates are very large, then downwind concentrations may also be large, even though the concentrations decay with distance from the leak in an exponential manner. When the leak rates are small, the downwind concentrations close to the leak site will be relatively small.

In Figure 1.2-29, we show the average downwind concentration per unit flow rate for the Aliso Canyon facility as an example. The model assumes that each well is a point source that emits an amount of methane equal to the maximum flow rate from the 2015 Aliso Canyon incident (16 kg/s = 57 t/hr) divided by the number of wells present. The top-left panel in Figure 1.2-29 shows the concentration (C) per leakage flow rate (Q) superimposed on a GoogleEarth image of the storage facility, with the boundaries of the facility marked in black. C has dimensions of mass per volume (e.g., kg m^{-3}) while Q has dimensions of mass per time (e.g., kg s^{-1}), making C/Q have dimensions of time per volume (e.g., s m^{-3}). The white contours indicate the contour levels for C/Q scaled by a factor 10^9. The complete set of downwind concentrations for all UGS sites in California is shown in Appendix 1.B. The calculated downwind C/Q ratios are particularly useful because the contour levels can be multiplied by the actual leak rate to obtain the average concentrations downwind of the UGS facility.

For example, the modeled Aliso Canyon C/Q field is shown in Figure 1.2-29 assuming that all 115 wells at Aliso Canyon each emitted 16/115 kg/s for a total emission equal to the peak of the 2015 Aliso Canyon incident. If we consider the white C/Q contour labeled 42

(42×10^{-9}) m^{-3} s, and multiply this value by the total facility leakage rate of 16 kg s^{-1}, we obtain 16 kg $s^{-1} \times 42 \times 10^{-9}$ m^{-3} s = 6.7×10^{-7} kg m^{-3} = 670 mg m^{-3}. In short, the contour labeled 42 in Figure 1.2-29 corresponds to a CH_4 concentration of 670 mg m^{-3}, which is approximately 1 ppmv, which would correspond to an elevation of 1 ppmv above the background, which is approximately 4 ppmv in the area of Porter Ranch (see Section 1.4.10.2). It is important to note that concentrations much higher than this calculated value (~10^3 times higher) were observed in the Porter Ranch neighborhood (see Section 1.4.10.3). The reason for this discrepancy between model and reality is that the model is time-averaged and does not account for local anomalous winds, for example canyon breezes that can advect leaking CH_4 directly down into the neighborhood. Furthermore, the SS-25 well was a point source, whereas this model assumes the equivalent leakage rate was spread out among 115 wells.

What good are these models if they cannot match observations? The fact is that these models can be very accurate if they are provided with accurate wind and flow-rate data. We have presented results here in the spirit of showing what is possible, and not to predict actual concentrations that can be used today for hazard assessment.

To summarize, acute LOC from high-pressure gas systems at UGS facilities can lead to very high flow rates, producing potentially catastrophic impacts near the leak source. And UGS facilities can also suffer from chronic low-level leakage that persists over time. Throughout the spectrum of leakage rates and durations, natural gas will disperse above ground as it flows away from the leakage source area. The patterns and degree of dispersion can be simulated for hazard assessment, risk assessment, emergency response planning, and land-use and facility planning purposes, provided the models use accurate local wind and leakage flow-rate data.

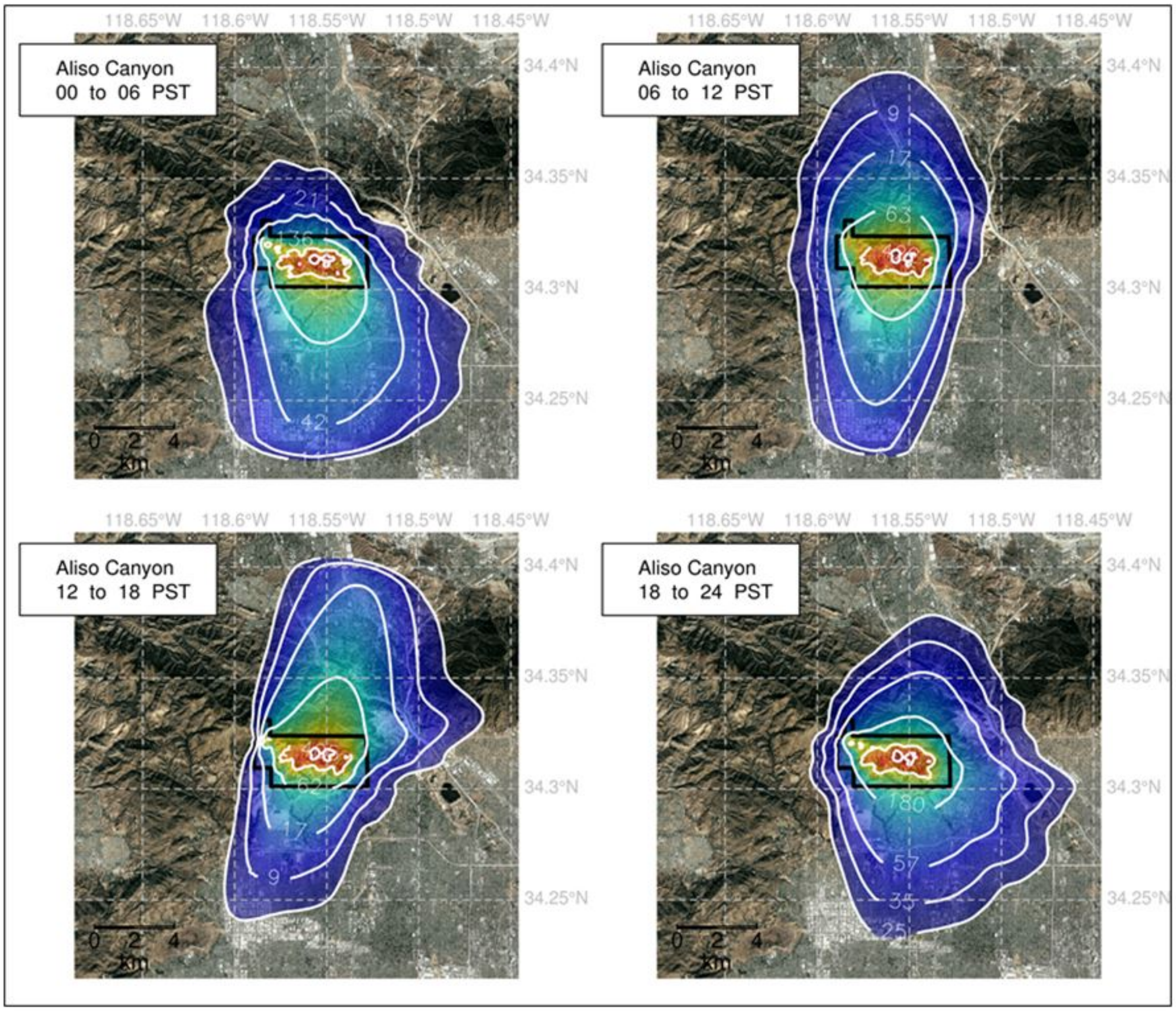


Figure 1.2-29. Simulated contours of atmospheric dispersion of leaking natural gas shown by contours of concentration divided by unit flow rate (C/Q) for four different periods during the day. The contour values are multiplied by 10^9. These are general results to demonstrate the modeling approach and the concentration values predicted here should not be used for hazard assessment.

1.2.8 Potential Impacts of LOC on UGS Infrastructure

Potential impacts of LOC on health and safety, including hazards of chemicals that could be released with leaking gas, e.g., mercaptan odorants, are discussed in Section 1.4. In this section, we discuss potential impacts to infrastructure. The dominant hazards from the release of high-pressure natural gas at UGS facilities include thermal radiation from sustained fire and collapse of buildings from explosions inside of buildings or in partially confined areas, e.g., areas partially enclosed by buildings. Decompression cooling as natural gas expands to atmospheric pressure can cause small leaks to turn into large leaks as pipeline or tank-wall steel becomes brittle and fractures during leakage, thereby creating a larger opening. Small LOC incidents, if ignited, can trigger much larger incidents as flames damage other infrastructure. The source of flowing gas can be from the ground (e.g., during a breach blowout), from around wells (e.g., well cellars), from the wellheads, flowlines, flanges, or any other surface components of the UGS system (e.g., Figure 1.0-1). As observed in the 2015 Aliso Canyon incident, unignited releases result in much smaller consequences for infrastructure. Because we are focused on impacts of LOC to infrastructure here, we assume that ignition sources exist and that ignition will occur provided the flammable gas is within its flammability concentration range.

The same methods used in the previous section to simulate dispersion of leaking natural gas can be used with flammability/explosion-limit estimates to delineate the extent of the hazard zone (Benjamin et al., 2016; SFPE, 2008). For UGS facilities with high-pressure natural gas, the size of fire and explosion hazard zones can be larger than the clustered or co-located infrastructure footprint, especially for facilities with co-located equipment, such as wellheads near gas processing equipment and operations offices. As an example of co-located equipment, we show in Figure 1.2-30 the McDonald Island Turner Cut station, which has two rows of wells on 25 ft spacing and operations and office space within 50 ft (15 m) of gas processing facilities within the same elevated structure.

Figure 1.2-30. Aerial view of the McDonald Island Turner Cut station showing control room (SW end of central structure) and gas processing facilities (NE end of central structure) and two WSW-ENE trending lines of wells on 25 ft (7.6 m) spacing on either side (north and south) of the central structure.

The area of hazard associated with damage to infrastructure will depend on the mode of failure, time to ignition, environmental conditions at failure point, and meteorological variables. For example, ignited releases can produce pool fires, jet flames, vapor cloud fires, or fireballs, all of which behave differently and exhibit markedly different radiation characteristics. The thermal radiation hazards from hydrocarbon pool fires depend on a number of parameters, including the composition of the hydrocarbon, the size and shape of the pool, the duration of the fire, its proximity to the object at risk, and the thermal characteristics of the object exposed to the fire (Smith et al., 2011; Jo and Ahn, 2002).

Accidental release of hydrocarbon vapors or intentional release (e.g., blowdown) of unwanted gas can result in large turbulent diffusion flames and flares (Dryer et al., 2007; Montiel et al., 1996; Sklavounos and Rigas, 2006). Thermal radiation from flares and turbulent flames can represent substantial hazard to personnel, equipment, and the environment. The base diameter of a flare stack, height of the stack, and composition of the burning substance are important variables in determining the radiation from turbulent jet flames. Horizontal jet dispersion models that characterize the concentration profile and fire models that characterize the radiative heat flux can estimate the ground area (hazard zone) affected by credible failure scenarios. For the purposes of this section, any and all infrastructure located within the hazard zone will be considered to be a total loss.

Under high leak rates, the downwind concentrations can be larger than the flammability or explosions limits. Flammability limits refer to the range of compositions, for fixed temperature and pressure, within which exothermic chemical reactions are possible. Flammability limits are given in terms of fuel concentration (by volume) at a specified pressure and volume. The lower flammability limit for pure methane is 4.4% (percent volume of air), while the upper flammability limit is 16.4%. For comparison, the lower and upper flammability limits of pure ethane are 3% and 12.4%, respectively.

If the leak rates are very high, then the downwind concentrations can be larger than the lower flammability limits. Results indicate that the C/Q contours (white contours in Figure 1.2-27) extend well beyond the extent of the storage facility (marked in black). This implies that the size of the hazard zone can be much larger than the infrastructure footprint, and that LOC failure consequences can be potentially very large.

This discussion of the high risk to UGS infrastructure associated with severe acute LOC incidents within the footprint of the UGS facility points to the need for clearly establishing the extent of the hazard zone. Design simulations and characterizing hazard zones at current facilities would allow development of safer site layouts and LOC risk mitigation for existing sites, e.g., through minimization of leakage and ignition sources. Buffer zones and sufficient spacing between potentially leaky components, along with open spaces between buildings, mitigate on-site LOC infrastructure risk by providing space for leaking gases to flow and disperse.

1.2.9 Risk to Underground Sources of Drinking Water (USDW) of UGS Failures

Stray gas migration into resources such as underground sources of drinking water (USDWs) associated with the oil and gas industry in general, rather than the UGS industry in particular, have been well documented across the United States. An example of a nationally recognized oil and gas stray gas migration case called the “Bainbridge Incident” occurred in Bainbridge Township of Geauga County, Ohio, in 2007 (Bair et al., 2010). Figure 1.2-31 is a downhole color photo of a stray gas impact to a domestic water supply documented during the Bainbridge Incident investigation (Bair et al., 2010). A total of 26 domestic water wells were impacted by this incident. This type of impact was caused by what is called “annular overpressurization.” Annular overpressurization occurs when the uncemented or poorly cemented annular space behind the production casing fails and allows high-pressured natural gas to migrate into the uncemented or poorly cemented annulus and enter into formations of lower hydrodynamic pressure, such as groundwater aquifers (Harrison, 1985). Figure 1.2-32 illustrates the potential pathway for stray gas migration in an overpressurized situation (Harrison, 1985). See also Figure 1.2-1 for pressure profiles that are relevant to Figure 1.2-32. In order to fully investigate and document a gas migration incident with a USDW, access to the USDW is necessary. Stray gas migration cases associated with UGS operations with impacts to USDW have not been well documented, but obviously have occurred (e.g., Araktingi et al., 1984). Without having direct access to monitoring wells or private, domestic water wells, determining whether USDW has been contacted by storage gas may be somewhat problematic. The main impact of methane is dissolution into USDW, and potential exsolution during use in homes or business, resulting in fire or explosion hazard. Other impacts can occur from components such as benzene that have maximum contaminant levels and which may be associated with the leaking natural gas from the reservoir.

Historic UGS Migration Issues in California

Evans (2009) documented a number of incidents of storage gas migration in California. Figure 1.2-22 lists the different storage gas migration incidents in California, with some that reached the surface and could have impacted USDWs (Evans, 2009). Numerous cases of stray gas migration to the surface (from both oil and gas and depleted storage fields) in California have been documented over the years due to failure and leakage of old wells. The Montebello UGS field had storage gas leaking to the surface along old oil and gas wellbores that had been drilled in the 1930s, and this storage facility was abandoned due to these gas leaks (Chilingar and Endres, 2005). The Playa del Rey oilfield, located in the Marina del Rey area of the Los Angeles Basin, was converted to underground gas storage in 1942 (Chilingar and Endres, 2005). Storage gas from the field has been leaking along old wellbores for a number of years, and typically this gas migrates into a shallow gravel deposit located several hundred feet below the surface (Chilingar and Endres, 2005). This storage gas migration from the Playa del Rey UGS is a documented case of storage gas impacting a groundwater aquifer in California. This permeable gravel aquifer can act to conceal the true magnitude of storage gas migration hazards (Chilingar and Endres, 2005).

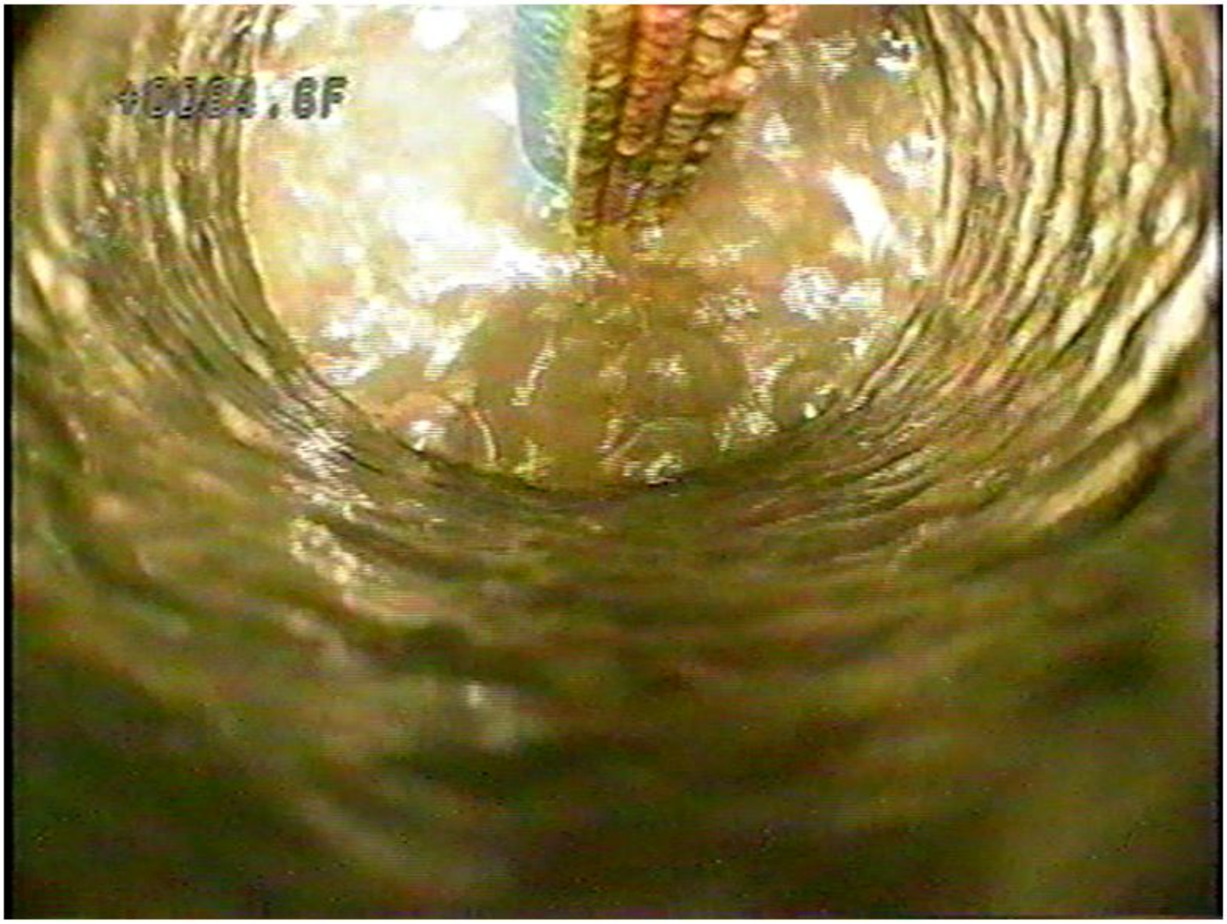


Figure 1.2-31. Example of stray gas migration impact to a USDW during the "Bainbridge Incident" (Bair et al., 2010).

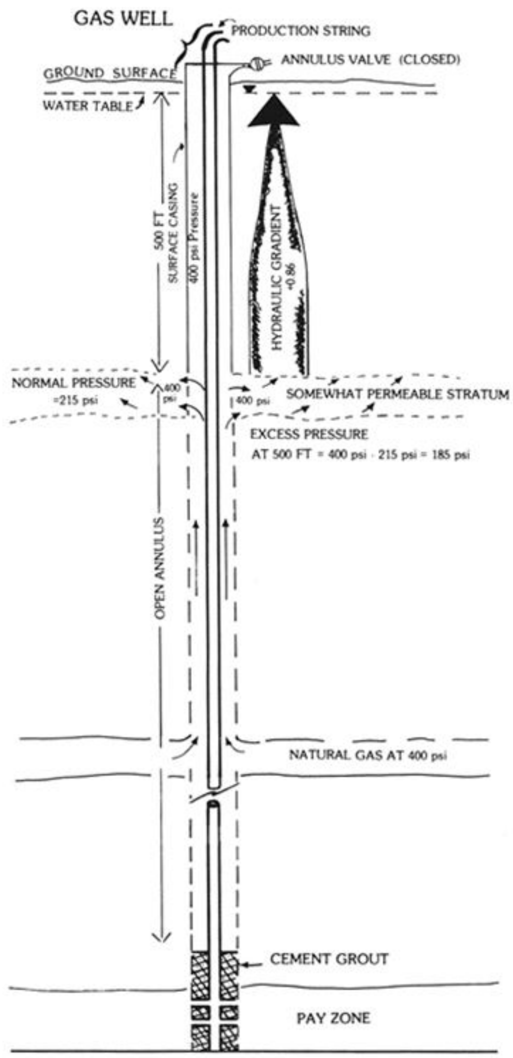


Figure 1.2-32. Example of an annular overpressurization scenario (Harrison, 1985).

1.2.10 Findings, Conclusions, and Recommendations

1.2.10.1 Overall Failure Frequency of UGS

Finding: Gas storage has been carried out in California for over 60 years at around 20 different sites. Several of the facilities have had serious LOC incidents. The most problematic of these sites have been closed and are no longer storing gas. Of the 12 sites open today, seven have incidents recorded in the literature. Although possibly artifacts of reporting or the fact that California's larger facilities are larger than the worldwide average, the failure rate of UGS in California appears to be higher than the worldwide failure frequency, which is about the same or lower than the failure frequency of oil and gas extraction operations (Evans, 2009).

Conclusion: Analysis of historic failure-rate statistics of California's UGS facilities points to a need for better risk management and improvement in regulations and practices. The Steering Committee views the new regulations proposed by DOGGR as a major step forward to reduce the risk of underground gas storage facilities, provided they are consistently and thoroughly applied and enforced across all storage facilities. In the future, careful re-evaluation of failure statistics, based on ongoing reporting and evaluation of incidents, can help determine whether and to what degree incident reductions have indeed been realized. (See Conclusion 1.1 in the Summary Report.)

Recommendation: At regular intervals in the future, DOGGR should assess—by re-analyzing incident reports—whether the frequency of UGS LOC incidents and other underground gas storage failures in California has actually been reduced. DOGGR should use these statistics to inform auditing processes for regulatory effectiveness. (See Recommendation 1.1 in the Summary Report.)

1.2.10.2 Focus on Subsurface

Finding: Queries of the database compilations of UGS incidents in California show that well-related leakage is by far the most common failure mode for LOC incidents in this state (Evans and Schulz, 2017). In contrast, compilations of UGS failures worldwide suggest that LOC incidents at UGS facilities worldwide are four times more likely to involve above-ground infrastructure (valves, pipes, wellheads, compressors, and other systems) as compared to incidents involving wells (Folga et al., 2016). It appears that California's subsurface LOC incidents are substantially higher than the worldwide average.

Conclusion: Although efforts to reduce LOC incidents should be expended on both surface and subsurface parts of the underground gas storage systems in California, there appears to be a large opportunity to reduce loss-of-containment risk by focusing on reducing subsurface integrity failures, in particular with regard to well integrity issues. Emphasis on subsurface failure modes is consistent with the focus of many of the requirements in DOGGR's interim and draft final regulations. (See Conclusion 1.2 in the Summary Report).

1.2.10.3 Require Tubing and Packer

Finding: In California, DOGGR regulates UGS wells and until now has not required the use of tubing and packer (two-point failure requirement) in UGS wells. Although this is how most UGS wells are operated in the U.S., it is inconsistent with the U.S. EPA's UIC program, which generally requires injection wells to utilize a tubing and packer configuration. But because UGS is specifically excluded from the UIC program, no such federal requirement exists. The new proposed DOGGR regulations, planned to take effect January 1, 2018, will require a two-point failure configuration for all UGS wells. By the exclusion of UGS from the UIC program, UGS wells have not been required to conform to the two-point failure requirement, resulting in widespread operation of UGS wells that produce and inject fluid through the A-annulus, with the casing serving as the only barrier between high-pressure gas and the environment, including along regions of casing without cement between the outside of casing and the borehole wall. If the SS-25 well at Aliso Canyon had been operated using tubing and packer for production and injection, the hole in the casing, suspected to have been caused by corrosion, would not have caused gas to escape to surface in the 2015 Aliso Canyon incident, because there would have been no reservoir pressure support and gas supply to the A-annulus to feed an ongoing blowout (major LOC incident).

Conclusion: We view the requirement in the new DOGGR regulations of a two-point failure configuration for all UGS wells as an important step in preventing major well blowouts and low-flow-rate LOC events. (See Conclusion 1.3 in the Summary Report.)

1.2.10.4 RA of Failure Scenarios

Finding: Compilations of UGS incidents worldwide and in California show that loss-of-containment (LOC) of high-pressure natural gas at UGS facilities often occurs by a chain of events that can be described by a failure scenario, which often involves human and organizational factors (HOFs). Queries of the updated database of Evans and Schultz (2017) show that well-related leakage is by far the most common failure mode for LOC incidents in California.

Conclusion: Failure scenarios involving initiating and multiple contributing events are common experience. Risk assessment and analysis methods and capabilities are well-developed and available from the engineering consulting industry to address failure scenarios in terms of understanding linkages between events, finding mitigating actions, and quantifying likelihood and assessing risk quantitatively and semi-quantitatively.

Recommendation: Operators of UGS facilities should utilize long experience and new and existing data to carry out quantitative risk assessment (what is the risk?) and risk analysis (what are the main sources of risk? How can risk be reduced?).

1.2.10.5 Basis for Failure Frequency Estimates

Finding: Different authors use a different denominator or basis for estimating failure frequency. E.g., some calculate failure rate on a per well basis, while others use per well-yr or per facility-yr.

Conclusion: The number of wells in use at any time over the course of operations of UGS facilities changes. Furthermore, there are abandoned wells that can be an issue for integrity but that are not used for storage. These facts make it difficult to form a meaningful metric for failure frequency using wells as the basis. We prefer to base failure frequencies on a per facility-yr basis. To rank sites and account for the larger number of wells at some sites, we suggest using a working-gas-capacity (Bcf) normalization, whereby the per facility-yr frequency is multiplied by the ratio of the California-average working gas capacity to the particular site working gas capacity. By this approach, one can account indirectly for the expected larger number of wells at larger sites, and normalize failure frequency to the average size site.

1.2.10.6 Natural Hazards Can Affect Integrity of UGS Facilities

Finding: Some California UGS facilities are located in regions with particular hazards that can affect UGS infrastructure, among which are seismic, landslide, flood, tsunami, and wildfire hazards. The risk arising from these hazards along with monitoring, prevention, and intervention needs, is now being assessed in the risk management plans that DOGGR now requires from each facility. Some natural hazards are more easily evaluated and mitigated than others; e.g., facilities potentially affected by periodic flooding are often protected by dams or placed on elevated land. Earthquake risk, on the other hand, is harder to assess and mitigate. Fault displacement and seismic ground motion can directly affect the surface infrastructure. Fault displacement can also affect wells at depth through shearing of the well casing if the well crosses the plane of the fault. Earthquake risk is a concern in several California facilities, such as Aliso Canyon, Honor Rancho, and Playa del Rey. SoCalGas is currently conducting an in-depth analysis of the risk related to the Santa Susana Fault, including a probabilistic seismic hazard analysis and a probabilistic fault displacement analysis.

Conclusion: Natural hazards can significantly affect the integrity of UGS facilities. (See Conclusion 1.4 in the Summary Report.)

Recommendation: Regulators need to ensure that the risk management plans and risk assessments required as part of the new DOGGR regulations focus on all relevant natural hazards at each facility. In-depth site-specific technical or geological studies may be needed to evaluate potential natural hazards associated with UGS facilities. For some facilities, earthquake risks fall under that category. (See Recommendation 1.4a in the Summary Report.)

Recommendation: Agencies with jurisdiction should ensure that earthquake risks (and other relevant natural hazards) are specifically investigated with in-depth technical or geological studies at all facilities where risk management plans suggest elevated hazard. (See Recommendation 1.4b in the Summary Report.)

1.2.10.7 Protect UGS from Attack

Finding: By analogy with oil and gas pipelines and wells, which have been the subject of numerous terrorist incidents around the world, UGS facilities in California are vulnerable to similar kinds of attacks.

Conclusion: It is well known that UGS facilities store a highly energetic fuel at high pressure, and that high-pressure pipelines of natural gas are ubiquitous at UGS sites. High-pressure pipelines of natural gas provide a source for explosion and fire that may make UGS sites attractive to terrorists or other groups or individuals intent on harm.

Recommendation: UGS sites should carry out a top-to-bottom review of mitigation of the threat of terrorism or other attacks by individuals or groups. Examples of mitigations of this threat include increasing security, decreasing the attractiveness of the facility as a target, maintaining an appropriate degree of confidentiality about operations, improving cyber security to avoid hacking attacks, and locking key valves and controls (Bajpai and Gupta, 2007).

1.2.10.8 Better Emissions Data and On-site Meteorological Stations

Finding: UGS sites in California are not uniformly equipped with meteorological stations or gas monitoring equipment. Bottom-up approaches that employ empirical emission factors are used to estimate emission inventories. These approaches do not provide the spatially and temporally varying emission data that are critical for estimating downwind consequences of leaks from individual UGS sites.

NOAA's Integrated Surface Database (ISD) provides meteorological data; however, the distances between California UGS sites and the closest stations can range from 2 to 25 km. Many UGS facilities are located in an area of complex topography, which can make the available meteorological data unreliable.

Conclusion: Although a range of practical and sophisticated modeling capabilities is readily available, lack of temporal and spatially varying emission data as well as reliable meteorological data make it difficult to accurately estimate the concentrations and dispersion of gas leakage from UGS facilities.

Recommendation: A practical implementation of continuous emission monitoring technology should be deployed at each UGS facility to provide reliable spatially and temporally varying data for analysis[2]. On-site weather stations should be installed at each UGS facility following National Weather Service (NWS) guidelines. These data could be used to generate accurate estimates of dispersion of leaking gases for risk assessment and emergency response purposes using readily available dispersion models.

2. The California Air Resources Board (CARB) implemented regulations effective October 1st, 2017 requiring continuous meteorological conditions at UGS facilities.

1.2.10.9 Risk to UGS Infrastructure from Fire and Explosions

Finding: Large accidental leaks of natural gas can pose a significant threat to people and property due to thermal radiation from sustained fires and collapse of buildings and infrastructure from explosions. Decompression cooling can cause small pipeline leaks to turn into large leaks. Horizontal jet dispersion models that characterize the concentration profile and fire models that characterize the radiative heat flux can estimate the ground area (hazard zone) affected by credible failure scenarios. Leak rates and meteorological data can be combined with flammability/explosion-limit estimates to delineate the extent of the hazard zone for risk assessment purposes.

Conclusion: The size of fire and explosion hazard zones can be larger than the footprints of local surface infrastructure, e.g., a compressor pad, gas-processing facility pad, or the clustered wellheads on pads of multiple deviated wells. This is especially true for facilities with gas processing equipment co-located with office/control facilities. LOC failure impacts to UGS infrastructure are potentially very large.

Recommendation: Hazard zones should be delineated for each UGS facility to focus risk mitigation on elimination of leakage and ignition sources to reduce the likelihood of fire and explosion, and to design surface infrastructure (e.g., buildings and their layout) to reduce the consequences (loss prevention) of fire and explosion if they should occur (safer site-use planning).

1.2.10.10 Impacts of Leakage on USDW

Finding: Stray gas migration from oil and gas operations into USDW has been well documented across the United States. Leakage of natural gas into USDW from UGS operations can occur and typically is caused by the phenomenon called “annular over pressurization.” Most UGS wells are constructed in a manner that results in an open annular space behind the production casing. This annulus is a potential avenue for gas migration from the gas storage reservoir of higher hydrodynamic pressure into formations of lower hydrodynamic pressure, including aquifers (Harrison, 1985).

Conclusion: Storage gas migration into USDW in California has occurred and has been documented in association with the Playa del Rey gas storage field (Chilingar and Endres, 2005). Other gas storage migration incidents into USDW may go undocumented due to the lack of groundwater monitoring wells or lack of reliance on domestic water wells for private water supplies that would detect the presence of stray gas. Storage gas migration to the surface in a number of California gas storage fields has occurred through leakage through faults and abandoned or improperly plugged oil and gas wells (e.g., Honor Rancho and Montebello) (Evans, 2009).

Recommendation: Implement the proposed DOGGR regulations to improve well integrity and require groundwater monitoring wells at UGS sites to detect possible stray gas migration to USDW aquifers.

1.2.10.11 Clustered vs. Dispersed Wells

Finding: UGS facilities developed in California depleted oil (DO) reservoirs utilize mostly vertical wells that are widely dispersed across the field. In contrast, UGS facilities developed in California depleted gas (DG) reservoirs are often deviated with closely spaced and centralized wellheads.

Conclusion: There are tradeoffs in risk management of closely spaced versus dispersed wellheads. Maintenance and observation of the wellheads is facilitated by clustering, but failure of a wellhead (e.g., a burning blowout) in close proximity to other wellheads can lead to multiple wellhead failures.

1.3 CAPACITY OF UGS SITES: EFFECTS OF AGE AND STORAGE INTEGRITY

1.3.1 Abstract

The capacity of UGS reservoirs can be affected by the age of the facility through (1) the effects of formation damage and related reservoir processes, (2) the loss of reservoir integrity through well or caprock seal failure. Any unintended impedance to the flow of fluids into or out of a wellbore (reduction in permeability) is referred to as formation damage (Petrowiki, 2017). Age-related processes affecting depleted oil and natural gas reservoirs include formation damage, grain alteration due to partially fluid-supported sediments, changes in reservoir pressure conditions, and changes in fluid contacts within the pore spaces of the reservoir. Of these, the factor with the greatest potential to affect storage capacity is formation damage, as it affects the productivity of a depleted oil and gas reservoir during gas withdrawal. Operators should carry out proactive approaches to identifying, addressing, and properly mitigating formation damage in advance of the reduction in formation permeability to avoid loss of gas storage reservoir capacity.

The majority of the depleted oil and gas fields converted to UGS in California were originally discovered and developed for oil and natural gas production from 1929 to 1958. Consequently, the majority of the wells used for UGS in California are older wells (see Section 1.1) and these have required extensive well work-overs targeting a variety of integrity-related issues, such as quantity and quality of cement and corrosion of casing. Well work-overs themselves can provide inherent risk and have the potential for accidental releases. The age of these wells and historic well construction practices dramatically increase the likelihood for LOC. Five gas storage fields within the Los Angeles area have experienced gas migration issues due to age of the wells, improperly plugged and abandoned wells that served as avenues for gas migration out of the reservoir, and reliance on repurposed gas storage wells. At the depleted Montebello oilfield in Los Angeles, gas had been injected by SoCalGas at a depth of 7,500 feet since the early 1960s (Bruno, 2014). Gas injection ceased in 1986 after significant gas seeps were discovered at the surface within a large housing development above the gas storage reservoir (Khilyuk et al., 2000). Soil-gas analysis had detected the presence of imported and processed storage gas, several homes were purchased and demolished, and soil-gas extraction system was installed (Miyazaki, 2009).

When old wells are taken out of service due to age or integrity failures, the capacity of a gas storage reservoir is impacted unless new gas storage wells are drilled and completed to retain gas storage capacity and deliverability. Regarding effects on capacity of reservoir integrity in depleted oil and gas field storage operations, the initial confining zone/caprock is relatively secure as evidenced by hydrocarbon retention (based on the thick cap that acts as a robust seal in preventing migration from the gas storage reservoir), but the seal can sometimes become degraded over time with repeated pressure and stress cycling. The maximum operational reservoir pressure may need to be reduced to manage reservoir integrity problems, thereby impacting capacity. By assessing gas storage reservoir integrity

using a holistic approach (i.e., utilizing multiple methodologies such as geophysical logging and pressure testing), the number of incidents associated with loss of storage integrity can be dramatically reduced, with the added benefit of maintaining storage capacity.

1.3.2 Historical Use Considerations (e.g., oil and gas production)

1.3.2.1 Introduction and Discussion

This section reviews the history of gas storage facility operations and discusses the effects on capacity of age and storage integrity failures. According to the Energy Information Administration, as of 2015 there were 415 natural gas storage fields in the United States, and approximately 79% of these gas storage fields are in depleted oil and gas reservoirs (Tomastik and Arthur, 2016). The first conversion of a depleted oil and natural gas field to underground natural gas storage (UGS) occurred in Zoar, New York, in June 1916 (National Fuel Gas, 2016). Figure 1.3-1 shows the surface infrastructure of the first gas storage operation in the United States.

Conversion to gas storage of depleted fields commenced after World War II and continued across the United States as the demand for natural gas increased. Many of the wells within these depleted oil and natural gas fields were drilled and completed in the early to mid-1900s. Conversion of these wells to gas storage was not without problems. Most of the well construction and cementing practices at that time were substandard compared with modern drilling and completion technologies and requirements. Due to older well construction and cementing practices followed many decades ago, older wells converted to gas storage undergo extensive well work-overs. Well work-overs can lead to remedial well construction and cementing operations as well as continued well integrity assessment (Figure 1.3-2).

Storage of natural gas in California started in the 1920s when SoCalGas began storing natural gas in large aboveground tanks to meet customer needs (SoCalGas, 2017a). In 1941, the company introduced an approach new to California—underground storage of natural gas in depleted oil and gas fields, with the commencement of underground storage at La Goleta in Santa Barbara County (SoCalGas, 2017a). The majority of the depleted oil and gas fields converted to UGS in California were originally discovered and developed for oil and natural gas production from 1929 to 1958 (ALL Consulting, LLC, 2015). Consequently, the majority of the wells used for underground gas storage in California are older wells (see Section 1.1) and have required extensive well work-overs targeting a variety of integrity-related issues of older wells, such as quantity and quality of cement and corrosion of casing.

Side bar: Description of the 2015 Aliso Canyon incident: SS-25 well blowout and kill attempts

Introduction

The 2015 Aliso Canyon incident was a subsurface blowout of a gas storage well (SS-25) that breached to surface and leaked approximately 100 thousand tons (~5 Bcf) of methane into the atmosphere over nearly four months without igniting (Conley et al., 2016). Only the 2004 Moss Bluff cavern storage well blowout exceeded the size of the 2015 Aliso Canyon incident, but the Moss Bluff natural gas ignited converting the methane to CO_2 making the Aliso incident the largest release of methane to the atmosphere in U.S. UGS history (Conley et al., 2016). The total amount of natural gas leaked was approximately 6% of the working gas capacity of the reservoir. This severe loss-of-containment (LOC) incident led to the evacuation of several thousand families from the Porter Ranch neighborhood downslope of the SS-25 well, families who either experienced health impacts or were avoiding potential health impacts.

In this brief side bar, we describe the main elements of the incident with an emphasis on the physical processes occurring in the well before and during attempts to kill the well. The account is relevant to risk because it illustrates a case in which the failure scenario was very difficult to address, which points out the value of risk mitigation and avoidance of failure scenarios. We do not discuss the emergency response, or impacts of the incident on the community, the environment, or the larger UGS industry, the full extents of which have yet to play out. We emphasize that the full root-cause analysis of the 2015 Aliso Canyon incident has not been published, so the account below is tentative but based on available records, documentation, and inference.

Background

The SS-25 well was one of 115 operational wells at the Aliso Canyon UGS facility at the time of the blowout. As with a bit fewer than half of the wells at Aliso Canyon, SS-25 was a re-purposed oil well with the original production casing from its construction in 1953. The SS-25 well was converted to use as a UGS well in 1973, and the last work-over of the well was in 1979, at which time a failed subsurface safety valve (SSSV, aka downhole safety valve (DHSV)) was removed. At some point, slots or ports were created likely for use of a sliding sleeve valve (SSV) at this location (depth of 8,451 ft) connecting the tubing and A-annulus (Figure SB-1) (Interagency Task Force on Natural Gas Storage Safety, 2016, p. 19).

The direct connection between the tubing and the A-annulus of this well is not a unique feature of the SS-25 well, but is in fact a common feature of UGS wells. This configuration in which both tubing and annulus are used for injection and production is non-standard in the oil and gas industry (outside of UGS) and not allowed under the U.S. EPA Underground Injection Control (UIC) program because it causes reliance on a single barrier (the casing) to hold the high pressure of the gas in the well. Normal oil and gas and wells (and injection wells in the UIC program) only produce (or inject) fluid through the tubing, and they utilize a packer to maintain isolation between the high-pressure of the reservoir and the A-annulus. By this standard approach, the A-annulus serves as a region in which pressure can be monitored and anomalies investigated, while the casing serves as a secondary barrier.

Blowout

Gas leakage was detected to be occurring from out of the ground on the hillsides below the ridge-nose location of the wellhead of SS-25 on or about October 23, 2015. Although it was considered at the time to be a straightforward operation to kill the well, ultimately eight unsuccessful well-kill attempts would be made between October 24, 2015, and late December by pumping heavy kill fluids and other materials down the well. In early November, attempts to carry out temperature logging, a standard approach to detect and locate subsurface leakage by means of sensing decompression cooling associated with subsurface blowouts, failed because of a blockage of methane hydrate at a depth of approximately 450 ft. (Methane hydrate is a water-methane compound similar to ice that forms at low temperatures in water-methane systems and is a good indicator of gas leakage in wells.) In order to facilitate completion of the temperature log, a coiled tubing rig was set up on November 4, 2015, at the SS-25 well with the goal of injecting hydrate inhibitor (glycol) fluid to wash out the hydrate blockage. A hydrate plug at approximately 450 ft depth was removed by this process.

Temperature and noise logs were obtained by November 8, 2015, and showed that there was no gas flow in the tubing down to 8,435 ft, but gas was flowing in tubing below that depth. It can be inferred from this evidence that gas was flowing up the A-annulus above 8435 ft. At some point in the timeline, a bridge plug was placed in the tubing at a depth of 8,393 ft to allow pressure testing of the tubing to determine its integrity. The tubing was subsequently perforated to connect the tubing and A-annulus above this plug. The methane hydrate plug at 450 ft depth is suggestive of the location of leakage from the A-annulus to the B-annulus (see Figure SB-1). A cooling anomaly at 890 ft depth was detected, suggestive of leakage from the B-annulus to the formation at the base of the surface casing (see Figure SB-1).

On November 13, 2015, one of the multiple top-kill attempts was carried out in which heavy kill fluid was injected. Instead of killing the well, the kill fluid came to surface and, along with high-pressure natural gas from the reservoir, excavated a crater north of the well. By December 22, 2015 following additional kill attempts, the single crater had grown to comprise a large crater on both sides of the SS-25 well approximately 25 ft deep, 80 ft long and 30 ft wide (2,400 sq. ft) (22 m_2) oriented subparallel to the ridge, the likely direction of maximum horizontal stress (Figure SB-2). The craters surrounded the well and thereby allowed the well casing to oscillate from side to side. The extreme motion of the well during the last top-kill attempts in late 2015 led responders to place a bridge-like structure across the craters approximately perpendicular to the ridge to stabilize the casing. From this point forward, the natural gas gushed out of the craters into the atmosphere along with entrained kill and reservoir fluids, although at some point in the timeline a heavy steel screen was placed over the craters in the attempt to catch some of the oily residues entrained with the gas.

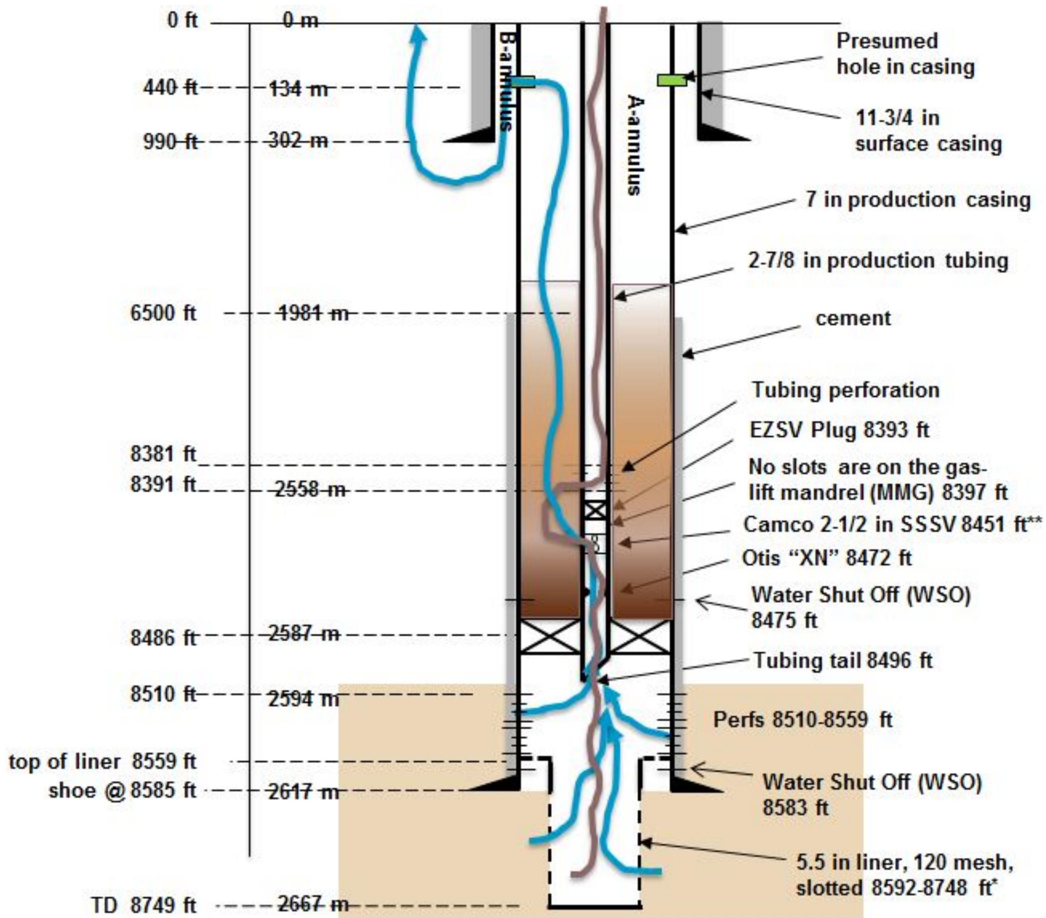


Figure SB-1. Sketch of the SS-25 well (not to scale) showing the complex geometry of gas flow (blue) and kill-fluid flow (brown). In particular, note that the tubing is connected to the A-annulus through slots in the tubing. Note further that at some point during the SS-25 blowout, a plug and tubing perforations were installed in the well at a depth of 8393 ft.

*The 120 mesh liner is believed to be 120 Gauge (0.120 inch).

**This is the location of a subsurface safety valve (SSSV) that was removed decades ago. At the time of the 2015 incident, there were slots in the tubing at this location connecting the inner tubing to the A-annulus, possibly remnants of an inoperable or missing sliding sleeve valve (SSV) installed at some point (Interagency Task Force on Natural Gas Storage Safety, 2016, p. 19).

Figure SB-2. The SS-25 wellhead is shown in the upper right-hand quadrant of this image along with the two craters extending diagonally from the well in the photo. Source: http://www.latimes.com/local/california/la-me-aliso-well-hole-20160115-story.html (Accessed 7/30/17).

Why was the SS-25 well hard to kill?

Simulations indicate the flow geometry within the well made the SS-25 very difficult to kill using top-kill approaches (Pan et al., 2018). In particular, the gas apparently flowed at high velocity through the open ports of inoperable (or missing) sliding-sleeve valve. In order to kill the well by a top kill, kill fluid would need to pool in the A-annulus to a height that would produce pressure high enough to overcome the gas flowing out of the tubing ports. Meanwhile, the only way for kill fluid to accumulate in the A-annulus was for it to exit the tubing through the perforations above the plug at a depth of 8393 ft. However, gas at high velocity was flowing upward in the A-annulus all the while that kill fluid was flowing through the perforations. Simulations show the flowing natural gas in the A-annulus was strongly entraining the kill fluid and carrying it upward in the well. The excavation of the craters is potential evidence of strong kill-fluid returns (Pan et al., submitted).

A relief well (Porter 39-A) milled into the SS-25 well below the packer on February 11, 2016, resulting in a flood of drilling fluid entering the well and reservoir. The high pressure of the drilling mud filled the bottom of the well and “U-tubed” up SS-25 killing the gas blowout within minutes. The SS-25 was subsequently filled with cement and abandoned.

Sources:

Interagency Task Force on Natural Gas Storage Safety (2016)

Denbury engineer:

(http://connect.spe.org/HigherLogic/System/DownloadDocumentFile.ashx?DocumentFileKey=4a50f78c-2906-c4d0-771d-0d9cb697470a (accessed 7/30/17)

LATimes, http://www.latimes.com/local/california/la-me-aliso-well-hole-20160115-story.html (accessed 7/30/17)

Pan, L., Oldenburg, C.M., Freifeld, B.M., and Jordan, P.D., Modeling the Aliso Canyon underground gas storage well blowout and kill operations using the coupled well-reservoir simulator T2Well, J. Petrol. Sci. and Eng., Vol. 161, pp 158-174.

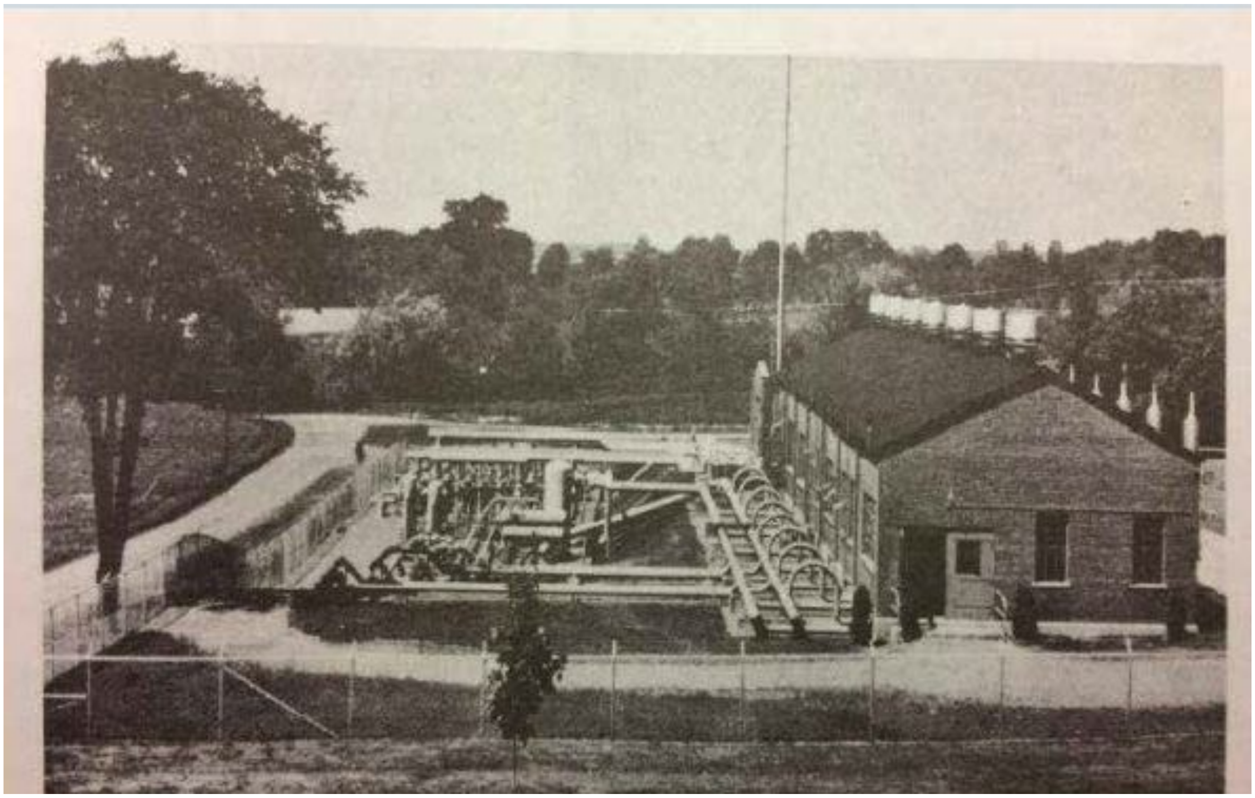


Figure 1.3-1. Photo of the nation's first underground gas storage field (Source: National Fuel Gas, 2016).

Figure 1.3-2. Example of a well work-over underway (Source: ALL Consulting, LLC, 2016).

1.3.3 Underground Gas Storage Capacity Can Be Affected by the Age of UGS Operation

1.3.3.1 Introduction and Discussion

Approximately 80% of the wells in United States UGS sites were completed in the 1970s or earlier, and have been exposed to decades of physical and mechanical stresses (Interagency Task Force on Natural Gas Storage Safety, 2016). The storage capacity of a UGS field converted from a depleted oil and natural gas reservoir can be affected by a number of different factors, including (GWPC and IOGCC, 2017):

1. Formation compaction and damage from the original oil, produced water, and natural gas extraction (i.e., formation damage);
2. Grain alteration due to partially fluid-supported sediments;
3. Changes in reservoir pressure conditions; and
4. Changes in fluid contacts within the pore spaces of the reservoir

The factor with the greatest potential to affect storage capacity is formation damage, as it affects the productivity of a depleted oil and gas reservoir during gas withdrawal. Formation damage is a generic term that refers to the impairment of the permeability of hydrocarbon-bearing formations by various adverse processes (Anyadiegwu and Muonagor, 2013). Formation damage is usually caused by physico-chemical, chemical, biological, hydrodynamic, and thermal interactions of the porous formation with particles and fluids and mechanical deformation of the reservoir under stress and fluid shear (Anyadiegwu and Muonagor, 2013). Such causes can include: (1) Cold fluid injection; (2) Cooling by gas expansion; (3) Incompatible/contaminated fluid invasion; and (4) High flow rate through the formation (Sutton and Roberts, 1974).

According to Benion and Jones (1994) formation damage falls into four broad categories based on the mechanism of its origin. They include:

1. Mechanically induced formation damage (phase trapping, fines migration, and solids entrapment);

2. Chemically induced formation damage (clay swelling and deflocculating, wax deposition, solids precipitation, acid sludge, stable emulsions, chemical adsorption, and wettability alternation);

3. Biologically induced formation damage (bacterial action); and

4. Thermally induced formation damage (elevated or reduced borehole temperatures).

Formation damage affects the deliverability of the gas storage reservoir by causing a reduction in the reservoir permeability and an increase in the well skin factor, which causes greater resistance to flow and reduces gas deliverability from the storage reservoir (Anyadiegwu and Muonagor, 2013). The zone with an altered permeability is called “skin” and its effect on the pressure or flow behavior of a well is called the “skin effect” (Hurst et al., 1969). The skin factor is a dimensionless pressure drop caused by flow restriction in the near wellbore environment (Petrowiki, 2017). Figure 1.3-3 is a graph showing the effects of skin on the deliverability of natural gas from a gas storage reservoir. The deliverability of working gas decreases as a result of skin increase, which indicates formation damage (Tureyen et al., 2000; Anyadiegwu and Muonagor, 2013).

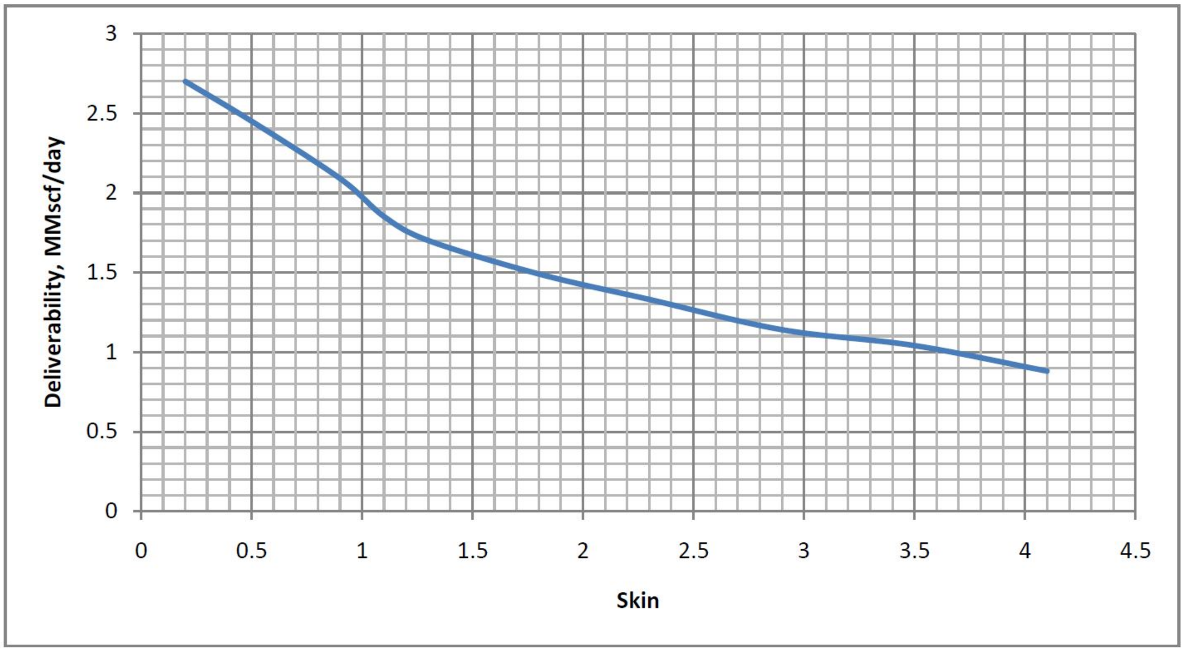


Figure 1.3-3. Plot of gas deliverability against skin for an underground gas storage reservoir (Anyadiegwu and Muonagor, 2013).

1.3.3.2 Addressing Formation Damage

Finding: The gas storage reservoir and its ability to deliver gas can be altered due to formation compaction and damage from long-term oil, produced water, and natural gas extraction resulting from grain alteration, changes to reservoir pressure conditions, and changes to the fluid contacts within the underground gas storage field (GWPC and IOGCC, 2017). Formation damage causes reduction in gas storage reservoir permeability which leads to a decrease in deliverability that dramatically impacts the effective capacity of the underground gas storage field (Anyadiegwu and Muonagor, 2013).

Conclusion: Because formation damage is more likely in older wells with long histories of production, UGS capacity can be affected by the age of the wells at the UGS facility and its history of operations.

Recommendation: Operators should carry out proactive approaches to identifying, addressing, and properly mitigating formation damage in advance of the reduction in formation permeability to avoid loss of UGS reservoir capacity. Being aware of formation damage implications during drilling, completion, injection, and production operations can help in substantially reducing formation damage and enhancing the ability of a well to inject and withdraw storage gas.

1.3.4 Underground Gas Storage Capacity Can Be Affected by Incidents of Reservoir Integrity Failure

1.3.4.1 Introduction and Discussion

Gas storage reservoir integrity can be defined by the geological and geomechanical conditions that are present within the storage reservoir that allows for safe operations beyond the wellbore (Katz and Tek, 1981; Interagency Task Force on Natural Gas Storage Safety, 2016). Loss of reservoir integrity, which results in subsurface leakage (formally LOC, but not necessarily LOC to the atmosphere), has a major impact on the capacity of the gas storage reservoir. Fundamentally, gas storage leakage from the reservoir carries two different types of risks (Folga et al., 2016):

1. The storage gas may migrate from the reservoir geologic structure, reaching drinking water aquifers and/or the surface, which represents a potentially significant risk to human health, safety, and the environment.

2. The stored gas may migrate from the storage reservoir geologic structure into overlying or adjacent porous and permeable formations and become nonrecoverable, which represents an economic risk.

Likely pathways for gas migration from the gas storage reservoir are caused by failure of vertical and/or lateral containment, which can be caused by artificial (well) penetrations, naturally occurring faults or fracture systems that may be transmissive, and compromising of the confining zone/caprock sequence due to reservoir overpressurization and/or overfilling of the structural or stratigraphic geologic spill points (Evans, 2008; Bruno, 2014; API, 2015; Folga et al., 2016; Interagency Task Force on Natural Gas Storage Safety, 2016; GWPC and IOGCC, 2017). In general, the loss of well integrity remains the primary factor in underground gas storage LOC incidents, with failure of subsurface reservoir integrity and surface operations being important secondary contributors (Evans, 2008; Bruno, 2014; API, 2015; Interagency Task Force on Natural Gas Storage Safety, 2016).

Bruno (2014) identified a number of potential leakage mechanisms associated with underground gas storage reservoirs and included the following:

1. Pore space/capillary pressure/permeation (caprock matrix)

2. Fault plane/fracture transmission (structural)

3. Induced fracturing, faulting, and bedding slip (geomechanical)

4. Dissolution channels/shrinkage cracks (geomechanical)

5. Overpressurization of the confining zone/caprock

6. Leakage along poorly cemented, improperly plugged, or abandon and unplugged wells.

Figure 1.3-4 further illustrates the additional mechanisms for leakage associated with underground gas storage reservoirs.

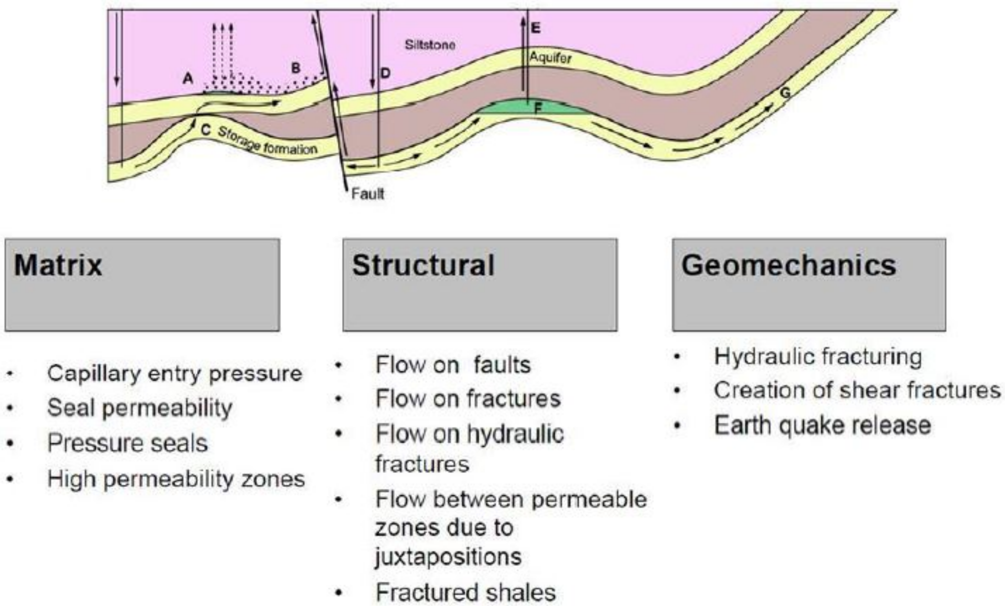


Figure 1.3-4. Identification of the leakage factors associated with gas storage reservoirs. Potential leakage pathways and mechanisms are indicated by the letters A-G as follows: (A) Gas leaks out of the reservoir through an eroded gap (missing local seal), (B) the gas pressure accumulated in the above-zone saline reservoir exceeds the capillary entry pressure in the regional seal and leaks upwards, (C) Gas leaks upwards along a conductive normal fault, (D) Gas leaks up a poorly cemented annulus of a UGS injection well, (E) Gas leaks up a poorly plugged abandoned well, (F) regional groundwater flow transports dissolved gas out of the structural closure, and (G) once out of the closure, groundwater transports gas to surface springs and into the atmosphere. (From IPCC (2005), but see also Nygaard (2012) and Bruno (2014)).

With depleted oil and gas field storage operations, the initial confining zone/caprock seal is relatively secure, but can sometimes become degraded over time with repeated pressure and stress cycling (Bruno, 2014). There have been 22 storage gas leak occurrences from a total of 485 porosity-storage facilities worldwide that could be attributed to natural gas migration through the confining zone/caprock sequence, corresponding to about 10% of all leakage occurrences investigated (Evans and Schultz, 2017). Evans and Schultz (2017) identify these failure mechanisms to include:

1. Failure of the confining zone/caprock sequence itself

2. Undetected or incorrectly characterized faults or fractures in the sequence

3. Combination of caprock failure and seal-bypass mechanisms.

Historically, California has been responsible for 18% of the underground gas storage incidents at depleted oil and gas fields due to gas migration to the surface along old wells and faults (Folga et al., 2016). California has a long history of oil and natural gas exploration dating back into the late 1800s, with many thousands of wells having been drilled across the state, often at very high densities prior to the existence of regulatory frameworks (Evans, 2008). Many oil and gas wells are not accurately located, and many well locations are not known at all. The majority of these old oil and gas wells have no, or at best, deteriorating casings and cement, and large numbers of these wells are unplugged or improperly plugged and abandoned (Evans, 2008). The Los Angeles area has been an area of intense hydrocarbon exploration and production since the late 1800s, with over 70 oilfields having been discovered, most within the early part of the 20th century (Bruno, 2014). Figure 1.3-5 is an example of oil and gas development in the Los Angeles area in early 1900s.

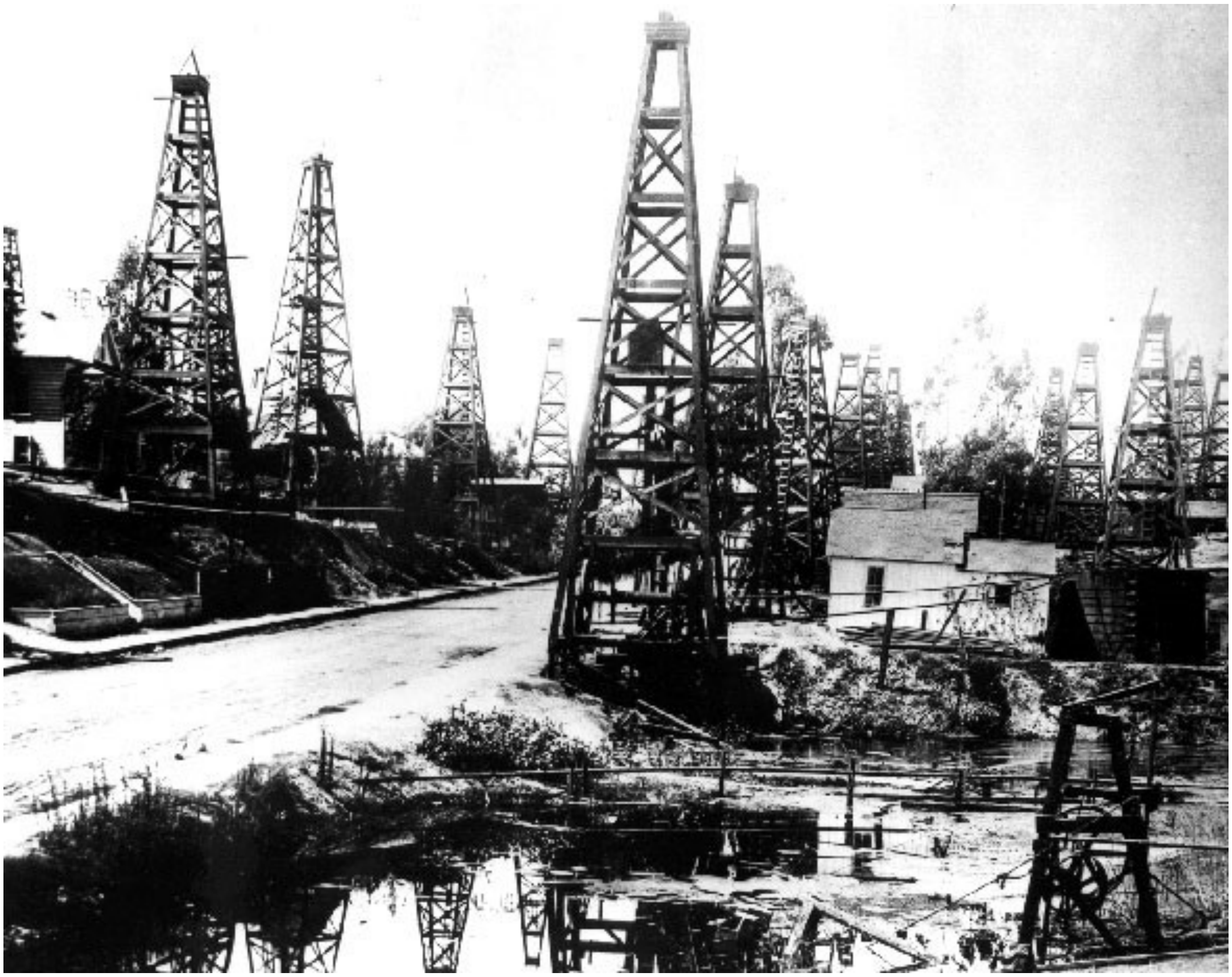


Figure 1.3-5. Photo of First Street, Los Angeles City oilfield, circa 1900 (Source: http://www.conservation.ca.gov/dog/photo_gallery/historic_mom/Pages/photo_04.aspx, accessed September 1, 2017).

Artificial well penetrations pose one of the greatest risks to reservoir integrity and loss of gas storage capacity, particularly in some of the southern California UGS fields, where thousands of poorly documented wells now lie beneath densely populated urban areas (Evans, 2008; Bruno, 2014). According to Bruno (2014), five gas storage fields that have operated in the Los Angeles area have experienced gas migration problems to the surface due in part, perhaps, to confining zone/caprock integrity issues and old wells. These include: Castaic & Honor Rancho, Playa del Rey, El Segundo, Whittier, and Montebello UGS fields (three of which have now been closed and abandoned—El Segundo, Whittier, and Montebello). Figure 1.3-6 shows the location of four of these five gas storage fields that experienced gas migration problems to the surface in the Los Angeles Basin area.

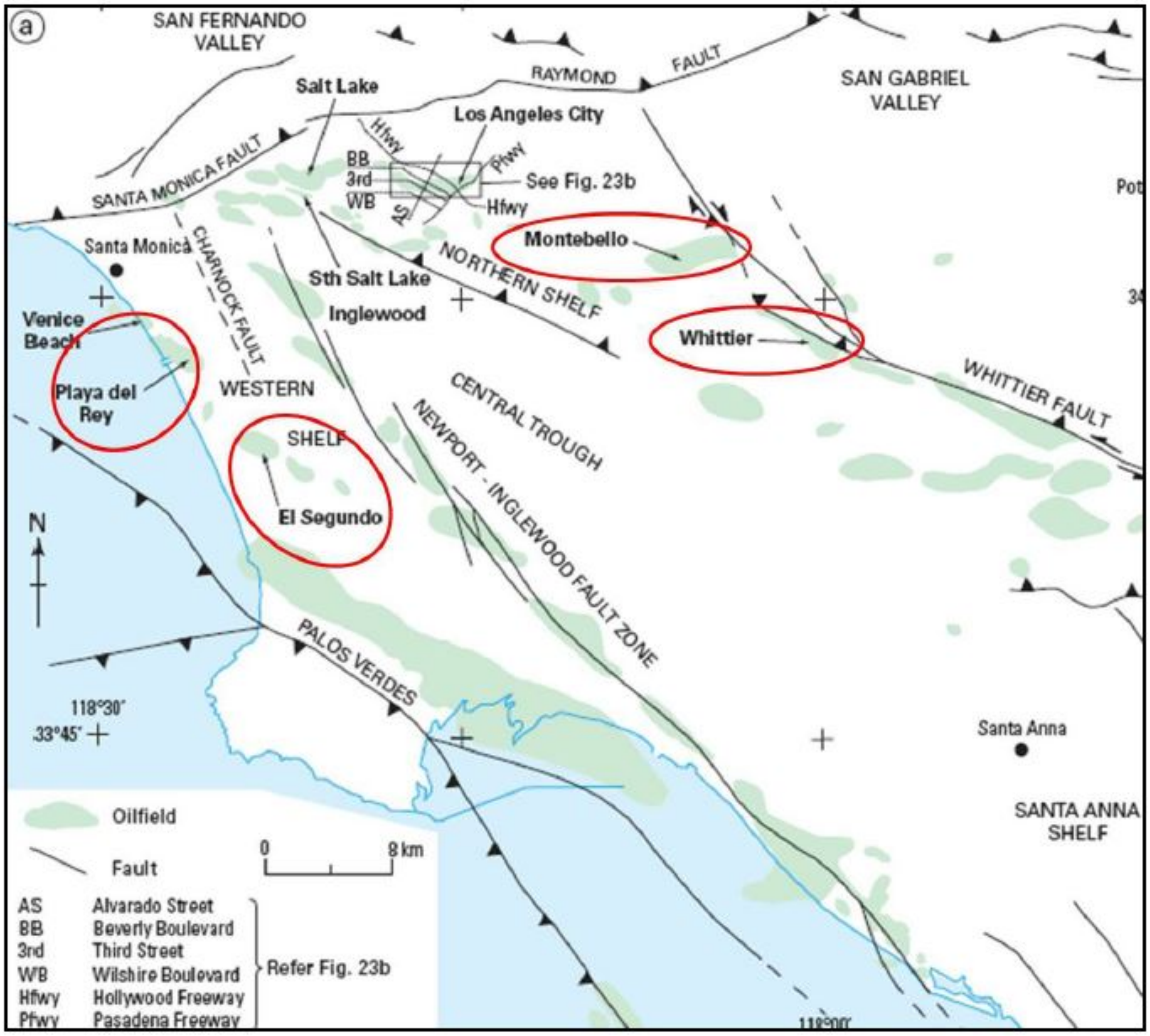


Figure 1.3-6. Map showing the location of four of the five gas storage fields with known surface leakage in the Los Angeles Basin area (Bruno, 2014).

The capacity of a gas storage reservoir can also be impacted by loss of old wells due to age, well construction, and well integrity failure (e.g., King and King, 2013). As these old wells are taken out of service and properly plugged and abandoned, new gas storage wells will need to be drilled and completed to retain existing gas storage capacity and deliverability. With the advent of horizontal drilling, many new gas storage wells are being drilled and completed horizontally within the gas storage fields throughout the U.S., which can dramatically increase capacity and deliverability of working gas within a gas storage reservoir.

With DOGGR's proposed regulatory changes that transition gas storage production from both production casing and tubing gas withdrawal and injection to injection and withdrawal through tubing and packer only (see Section 1.6), there will be a reduction in effective gas storage capacity and deliverability because of the reduced effective diameter of the well. To address these proposed regulatory changes, California gas storage operators will need to consider drilling and completing a number of new gas storage wells or alter existing well construction operations to increase capacity and deliverability. Currently, many of the wells in the gas storage fields in California utilize larger diameter production casings and a liner set across the storage formation. Injection and withdrawal operations are typically through smaller diameter tubing (such as 2-3/8" or 2-7/8"). If this is the case in most of the storage fields in California, larger diameter injection/withdrawal tubing could be used to increase injection and deliverability from the gas storage reservoirs.

1.3.4.2 Need for Stronger Regulations to Avoid Loss of Storage Capacity

Finding: Loss of reservoir integrity is a failure of UGS that results in closing of UGS reservoirs, or shutting in of certain wells, or requirement to operate at lower pressure. California UGS has experienced multiple LOC incidents due to reservoir integrity failure, which resulted in storage gas migration through old oil and gas wells back to the surface.

Conclusion: Gas storage reservoir integrity can be defined by the geological and geomechanical conditions that are present within the reservoir that allow for safe operations beyond the wellbore. Likely avenues for gas migration from the reservoir are caused by failure of vertical and/or lateral containment, which can be caused by artificial (well) penetrations, naturally occurring faults or fracture systems that may be transmissive, compromising of the confining zone/caprock sequence due to reservoir overpressurization, and overfilling of the structural or stratigraphic geologic spill points (GWPC and IOGCC, 2017). Fundamentally, UGS reservoir integrity carries two different types of risks: the release of gas from the storage reservoir that reaches aquifers and/or the surface, or migration of storage gas from the reservoir into overlying or adjacent geologic formations, where it becomes nonrecoverable.

Recommendation: More stringent underground gas storage regulations should be developed to require more technical, geologic, and engineering data to better characterize the gas storage reservoir. By assessing gas-storage-reservoir integrity using a holistic approach (i.e., utilizing multiple approaches such as geophysical logging and pressure testing), the number of incidents associated with gas-storage-reservoir-integrity failure can be dramatically reduced with the added benefit of avoiding loss of storage capacity.

1.4 HUMAN HEALTH HAZARDS, RISKS, AND IMPACTS ASSOCIATED WITH UNDERGROUND GAS STORAGE IN CALIFORNIA

1.4.1 Abstract

In Section 1.4, we assess the environmental public and occupational health hazards associated with underground gas storage (UGS) in California. We use four primary approaches: (1) an analysis of air toxic emission data reported to regional air districts and to the state; (2) a proximity analysis of populations near UGS facilities and their potential exposure to toxic air pollutants and natural gas fires and explosions using numbers, density, and demographics of people in proximity to UGS facilities and air dispersion modeling; (3) an assessment of air quality and human health impact datasets collected during the 2015 Aliso Canyon incident; and (4) an assessment of occupational health and safety hazards associated with UGS. The approach we take follows the general recommendations of the National Research Council to compile, analyze, and communicate the state of the science on the human health hazards associated with UGS in California.

Human health hazards of underground gas storage include exposures to toxic air pollutants as well as to explosions and fires during normal operations and/or large loss-of-containment (LOC) events. There is also a possibility of subsurface migration of gases and other fluids associated with gas storage into groundwater resources that may be used currently or in the future for drinking water and other uses that can form exposure pathways to people.

Our assessment of the scientific literature, available air pollutant emissions inventory, air pollution and human health monitoring datasets, and population characterization for community and occupational exposures indicate the following:

1. There are a number of human health hazards associated with UGS in California that are predominantly attributable to exposure to toxic air pollutants and gas-fueled fires or explosions during large LOC events. However, many UGS facilities also emit multiple health-damaging air pollutants during routine operations—formaldehyde in particular, which is of concern for the health of workers and nearby communities.

2. Large LOC events (e.g., the 2015 Aliso Canyon incident) can cause health symptoms and impacts in the nearby population and are a key challenge for risk management efforts.

3. UGS facilities located in areas of high population density and in close proximity to populations are more likely to cause larger population morbidity attributable to exposures to substances emitted to the air than facilities in areas of low population density or further away from populations.

4. During large LOC events, if emitted gases are ignited, the explosion hazard zone at UGS facilities can extend beyond the geographic extent of the facility, creating

flammability hazards to nearby populations.

5. Workers on site are likely exposed to higher concentrations of toxic chemicals during both routine and off-normal operations, and workers on site have greater chance of exposure to fire or explosions during LOC events.

6. There is uncertainty with respect to some of the mechanisms of human health harm related to the 2015 Aliso Canyon incident and other UGS LOC events in the future. This is mostly attributable to the lack of access to data on the composition of stored gas in the facilities and limitations of air quality and environmental monitoring during and after these events. While our research team attempted repeatedly to obtain the relevant gas composition data, we were unsuccessful.

7. California-specific as well as other peer-reviewed studies relevant to California on human health hazards associated with UGS facilities are critically scarce.

Multiple recommendations emerged from our research that could help to reduce the risk of UGS facilities in California and would greatly benefit the effectiveness of risk managers to protect nearby human populations from the health risks of environmental exposures sourced from UGS facilities. Our recommendations include but are not limited to the following:

1. Require that the composition of gas withdrawn from the storage reservoir over time be disclosed along with any chemical use on site that could be leaked, intentionally released, or entrained in gas or fluids during LOC events.

2. Require facility-specific meteorological (e.g., wind speed and direction) data collection equipment be installed at all UGS facilities[3].

3. Require that improvements to air quality and human health monitoring approaches be implemented both during routine operations and during LOC events.

3. The California Air Resources Board (CARB) implemented regulations effective October 1st, 2017 requiring continuous measurement of meteorlogical conditions at UGS facilities.

4. Require that steps be taken to decrease exposure of nearby populations to toxic air pollutants emitted from UGS facilities during routine operations and LOC incidents. These steps could include the increased application and enforcement of emission control technologies to limit air pollutant emissions, the replacement of gas-powered compressors with electric-powered compressors to decrease emissions of formaldehyde, and the implementation of science-based minimum-surface setbacks between UGS facilities and human populations.

5. Require that UGS workplaces conform to requirements of CalOSHA and federal OSHA to protect the health and safety of on-site workers. On-site workers that include but are not limited to employees, temporary workers and independent contractors should fall under these regulations regardless if operators are legally bound to comply.

1.4.2 Introduction

Section 1.2 of this report describes a number of underground gas storage (UGS) release mechanisms of high-pressure gas from the surface and subsurface parts of UGS systems. In this section, we extend the discussion of these potential emissions and releases to the environment to assess population exposures and summarize the associated hazards in the context of community and occupational health.

The documented human health hazards associated with UGS facilities include exposure to toxic air pollutants. These air-pollutant species are emitted through intentional and unintentional releases at and near the facility during normal operations, and minor and major loss-of-containment (LOC) incidents. Because of uncertainties about emissions and dispersion, addressing exposures and health impacts from LOC incidents is a major challenge for risk management. Another obvious human health concern for UGS facilities is the risk of exposure to fires, explosions, and secondary conflagrations attributable to the ignition of flammable natural gas, especially during large LOC events.

The human health hazards and risks from UGS facilities depend on the following factors:

a. Composition of stored, withdrawn, and stripped and compressed gas

b. Depleted hydrocarbon reservoir (DHR) type (e.g., depleted gas (DG) or depleted oil (DO))

c. Age and mechanical integrity of the subsurface and surface infrastructure

d. Type and number of gas compressors

e. Long-term expected emissions rate of chemical constituents from the wells

f. Magnitude and duration of emissions during LOC incidents

g. Atmospheric dispersion conditions during the period of release[4]

h. Number and density of gas storage, oil and gas production, and other wells in the vicinity of a loss of zonal isolation (i.e., subsurface LOC)

i. Activities, work and break locations of on-site workers and contractors

j. Location and density of downwind populations

k. Location of sensitive populations as represented by the very young, the elderly, women of childbearing age, schools, child care facilities, hospitals, and elderly care facilities in relation to the UGS facility; and

l. Prevalence of groundwater aquifers proximal to UGS facilities.

The approach we take to assess human health hazards and impacts follows the general recommendations of the National Research Council (1983; 1994; 1996; 2009) to compile, analyze, and communicate the state of the science on the human health hazards associated with UGS in California.

We divide our assessment on the public health dimensions of UGS storage into four approaches.

1. **Bottom-up approach using emissions inventories:** We first employ a bottom-up approach to explore hazards associated with UGS following the standard hazard assessment framework. In this approach, we characterize available data on the routine and off-normal emissions profiles of UGS facilities in California, and then identify chemical-specific human-health-relevant toxicity data, where available, and discuss chemical hazards based on annual mass emitted and toxicity.

2. **Identification and assessment of source-receptor relationships:** Our second approach to assessing public health hazards of UGS facilities uses source-receptor relationships and air dispersion modeling for routine emissions and LOC incidents. We employ source-receptor relationships to assess the physical hazards associated with explosion and flammability potential at UGS facilities in the case of large LOC incidents. In this approach, we evaluate potential exposures of nearby populations and other sensitive receptors to air pollutants emissions and potential fires and explosions from UGS facilities.

4. In the case of large emissions of flammable gases, atmospheric concentration and flammability of the gas and ignition source potential are the factors that determine the health and safety risks and impacts of fire/explosion.

3. **Aliso Canyon UGS Facility well blowout LOC Case Study:** We examine the 2015 Aliso Canyon incident involving the SS-25 well blowout as a community- and occupational-health case study of a large LOC incident. In this case study, we review and assess the air, environment, and human health impacts monitoring that occurred in the community nearby the Aliso Canyon storage facility and report findings, conclusions, and data gaps.

4. **Occupational aspects of UGS in California:** Finally, we examine the occupational health dimensions of UGS in California, identifying health and safety hazards facing workers in the context of routine activities and large LOC events (e.g., the 2015 Aliso Canyon incident).

We conclude this section with a summary of our key findings and conclusions as well as our policy and future research recommendations.

1.4.3 Framing the Hazard and Risk Assessment Process

Evidence-based policy and risk management plans for UGS sites require information on the hazards, risks, and impacts posed by these facilities. The terms *hazard*, *risk*, and *impact* are often used interchangeably in everyday conversation, whereas in a regulatory context they represent distinctly different concepts with regard to the formal practice of risk assessment and risk management. A *hazard* is defined as any biological, chemical, mechanical, environmental, or physical stressor that is reasonably likely to cause harm or damage to humans, other organisms, the environment, and/or engineered systems in the absence of control (Sperber, 2001). *Risk* is the probability that a given hazard plays out in a scenario that causes a particular harm, loss, or damage. (National Research Council, 2009). *Impact* is the particular harm, loss, or damage that is experienced if the risk-based scenario occurs. In the context of impacts related to exposure to radiation, food, water, or air, *hazard* can be considered an intrinsic property of a stressor that can be assessed through some biological or chemical assay. For example, a pH meter can measure acidity, particle disintegration counters can detect ionizing radiation, cell or whole animal assays, etc., can detect biological disease potency. These types of tests allow us to declare that a substance is acidic, radioactive, a mutagen, a carcinogen, or other hazard. *Hazard* can also refer to the potential for physical harm, as for example occurs when a person is exposed to fire or a collapsing building. However, defining the probability of harm requires a receptor (e.g., human population or high-value resource) to be exposed to the hazard, and often depends on the vulnerability of the population (or receptor based on age, gender, and other factors). As a result, risk is extrinsic and requires detailed knowledge (scenarios) about how a stressor agent (hazard) is handled, released, and transported to the receptor populations. In its widely cited 1983 report, the National Research Council first laid out the now-standard risk-analysis framework consisting of research, risk assessment, and risk management as illustrated in Figure 1.4-1 (National Research Council, 1983). The National Research Council proposed this framework to organize and evaluate existing scientific information for the purpose of decision-making. In 2009, the National Research Council issued an updated version of its risk assessment guidance titled “Science and Decisions: Advancing Risk Assessment” (National Research Council, 2009). This report reiterated the value of the framework illustrated in Figure 1.4-1, but expanded it to include a solutions-based format that integrates planning and decision-making with the risk-characterization process. The National Research Council risk framework illustrates the parallel activities that take place during risk assessment and the reliance of all activities on existing research. These activities combine through the risk characterization process to support risk management.

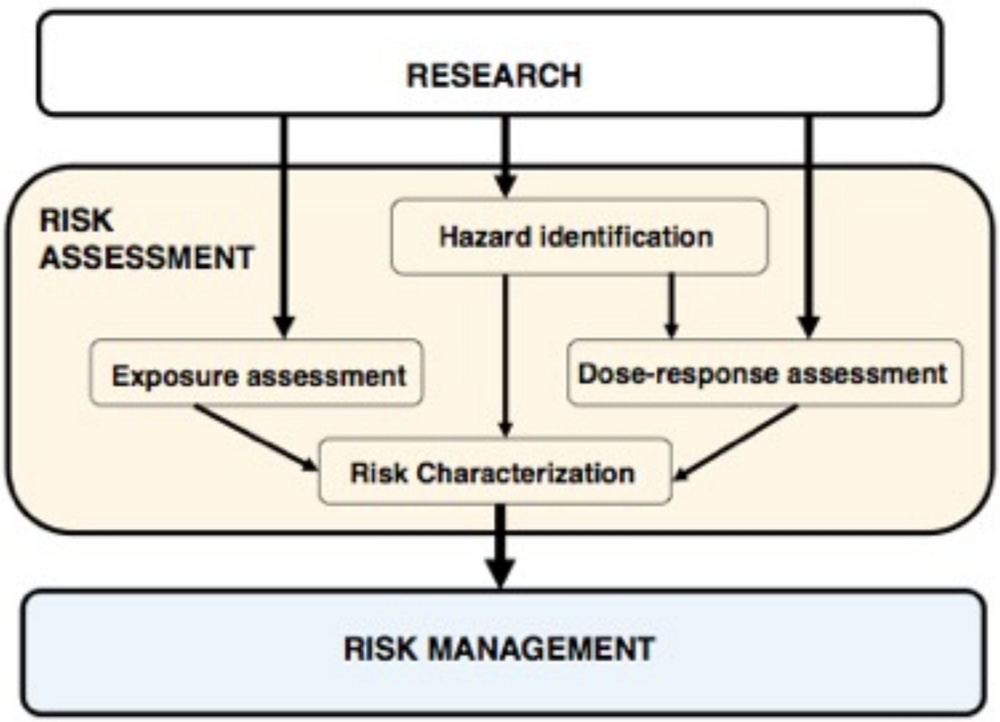


Figure 1.4-1. The National Research Council (1983) Risk Analysis Framework.

In using the framework in Figure 1.4-1, the first task in the risk analysis process is to identify features, events, and processes (FEPs) associated with an activity that could cause harm. These are called *hazards*. Any given hazard may or may not be a problem. It depends on the answers to two additional questions. First, is the hazardous condition likely to result in a population being exposed to the hazard? Second, what will be the impact if the hazardous exposure does occur (dose-response)? If we know the magnitude of a specific hazard exposure and the relationship between the magnitude of exposure and response or harm, then we can estimate the risk associated with that hazard. In cases where the hazardous condition is unlikely or where, even if it did occur, the harm is insignificant, then the risk is low. Risk is only high when the hazardous condition is both likely to occur and would cause significant harm if it did occur. Of course, there are many combinations of likelihood and harm possible.

Formal risk analysis presents difficulties, because we often lack:

- Data on all the possible hazards
- Comprehensive understanding and definition of all of the failure scenarios
- Information on the likelihood and magnitude of exposure
- Data to support an understanding of the relationship between exposure (dose) and harm (response).

If a hazard has not been identified, then it is difficult to develop steps to mitigate potential harm in a risk management plan. In this case, a useful approach is to avoid the problem where possible, for example by choosing chemicals that are better understood, less toxic, or more controllable rather than choosing ones for which there is little toxicity information or poor understanding of the relationship between the hazard and risk to the environment and/or to public health. Options for addressing hazards when information is missing are discussed more in Section 1.6, which presents recommendations for risk management.

Although one can attempt to identify *all* hazards associated with UGS in California, it is important to note that this does not mean that all hazards that are identified present risks. A formal risk assessment is required to estimate risk associated with any given hazard. A formal risk assessment is a significant site-specific undertaking that is beyond what was possible in this report. However, this section, along with Section 1.6, describes the structure and content of a site-specific risk assessment for UGS sites. Among the goals of this section are to identify community and occupational hazards and highlight those where additional study may be warranted in the context of developing and implementing risk management and mitigation options for UGS operations.

1.4.4 Scope of and Approach to Community and Occupational Health Assessments

1.4.4.1 Community Health Assessment Scope and Approach

This community health assessment (Section 1.4.7, 1.4.8, 1.4.10) evaluates health and safety hazards to communities near UGS facilities in California considering two emissions scenarios, routine and off-normal (e.g., loss-of-containment). The routine emissions scenario includes routine and modest but continuous or periodic (e.g., blow down of tanks and other equipment) emissions, while the off-normal emissions scenario includes a massive LOC release (e.g., the 2015 Aliso Canyon incident). For both scenarios, there are health and safety hazards to consider.

Regardless of the emissions scenario, a conservative approach is taken to estimate population and sensitive receptor (e.g., schools, daycare centers, elderly care facilities, etc.) exposure potential. We use radially symmetric buffers to identify potentially exposed populations near to actual California UGS facilities, regardless of average meteorological conditions. This conservative approach assumes that emissions—whenever they occur—may be dispersed in any direction by the currently prevailing winds and to various distances from each UGS facility.

We created the buffers using a two-tiered approach. Tier 1 includes any open (active or idle) wells within gas storage reservoirs. Tier 2 includes any well (active, idle, or plugged) in the field area that could serve as a potential conduit for gas migration.

At various buffer distances, we identify populations with potential for exposure from UGS facility emissions using total population counts. We also identify vulnerable populations and sensitive receptors, including schools, elderly care facilities, and daycare facilities located within buffers at various distances from each UGS facility.

During routine operations, the majority of methane emissions and co-emitted health-damaging air pollutant species come from above-ground infrastructure (see Section 1.5). However, given uncertain spatial estimates of above-ground infrastructure (e.g., compressor stations), this community health assessment assumes that compressors and other relevant above-ground infrastructure are located within the two-tiered boundaries created using well locations.

We lack detailed emissions information and gas composition data from the California UGS facilities to model dispersion of specific toxic air pollutants. To further clarify our community health assessment methodology, we use annual average wind roses and create asymmetric contours to identify how emissions are likely to disperse under average meteorological conditions. We then calculate the relative concentration of air pollutants/mass flow rate of emissions across space to spatially depict relative hazard in terms of exposure to nearby populations. We also use methane emissions data to model dispersion of methane at each site and to better estimate flammability and/or explosive potential (see Section 1.5). Finally, we include an assessment of the human health hazards and impacts of the Aliso Canyon SS-25 LOC event using available data.

1.4.4.2 Occupational Health Assessment Scope and Approach

This occupational health assessment (Section 1.4.11) evaluates health and safety hazards to on-site workers at UGS facilities in California, including employees and contracted or temporary workers (contractors). The assessment in this section considers health and safety hazards associated with most routine and off-normal emissions scenarios, including LOC events. As with the community health assessment, the occupational health assessment focuses on health and safety hazards from potential exposures to toxic air pollutants, fire, and explosions.

Similar to the community health assessment, the lack of detailed emissions information and gas composition data from California UGS facilities limited the scope and detail of our assessment. Additionally, a lack of access to occupational air-monitoring data limited our capacity to consider whether on-site exposures posed a health risk to workers. Information was gathered from a variety of sources, including UGS facility site visits, operators, and state agencies.

1.4.5 Toxic Air Pollutant Emissions from UGS Facilities

UGS facilities emit compounds into the air that can come into contact with workers and nearby populations. Stored or pipeline gas may be released into ambient air intentionally (e.g., blowdowns) or accidentally (e.g., leaks, large LOC events). While natural gas is primarily methane (CH_4), a wide variety of substances are admixed with injected natural gas during residence in underground storage reservoirs in California, in particular in the depleted oil (DO) reservoirs. While the majority of these contaminants are removed during gas processing before delivery back into the natural gas distribution system, they can be emitted to the atmosphere/environment in the case where natural gas leaks out of the reservoir or any component of the surface infrastructure (e.g., flowline(s)) prior to gas processing, as occurred during the 2015 Aliso Canyon incident. Aboveground infrastructure, including compressor stations, also emit compounds into the ambient air during normal operations. This section uses available information from emissions inventories and available toxicity information to (1) identify known pollutants historically emitted from UGS facilities in California, (2) discuss acute and chronic toxicity for non-cancer and cancer endpoints associated with the identified chemicals, and (3) prioritize chemicals known to be emitted from UGS facilities by annual mass emitted and toxicity for future monitoring and risk assessment considerations. Data gaps and limitations are discussed.

1.4.5.1 Characterization of UGS Facility Emissions

The California Air Toxics "Hot Spots" Information and Assessment Act (AB 2588) of 1987 requires quantification of emissions from stationary sources, including UGS facilities. The Air Toxics Hot Spots Program requires facilities to update emissions inventory data at least every four years, and requires reporting of both criteria pollutants (e.g., nitrogen oxides, sulfur oxides, carbon monoxide) and other toxic air pollutants that present a chronic or acute threat to public health. The California Air Resources Board (CARB) compiles and maintains a list of substances that must be reported under AB 2588, and evaluates substances listed by various government and scientific bodies (e.g., National Toxicology Program, International Agency for Research on Cancer, etc.) (CARB, 2016c). A full list of substances for which emissions must be quantified is presented in Appendix 1.A of the Emission Inventory Criteria and Guidelines Report (CARB, 2007).

UGS facilities report annual emissions by mass for criteria pollutants (tons/year) and toxic air pollutants (pounds/year) to regional air districts. Annual emissions by facility are then compiled by CARB and made publicly available via a Facility Search Engine (CARB, 2017a). South Coast Air Quality Management District (SCAQMD) also makes emissions data for facilities in their regional district publicly available through the Facility Emissions Search Tool (SCAQMD, 2017b). Of California UGS facilities in California, three operational facilities (Aliso Canyon, Honor Rancho, Playa del Rey) and one former facility that has indications of continued use (Montebello) are located within the SCAQMD, and have emissions reported online through both SCAQMD and CARB.

Emissions reporting may vary by regional air district. Facilities may report emissions from equipment (compressors, storage tanks, dehydrators, etc.) and processes using site-specific factors or default factors, if available. Routine (e.g., maintenance, blowdowns) and non-routine (shutdown, spills, equipment breakdown, etc.) are included in annual reporting, and facilities may be required to report emissions from all permitted and non-permitted equipment and processes. Facilities also may have the option to aggregate similar combustion sources (same type, same rating, same type of fuel). Air districts then calculate annual emissions based on throughput from the facility and reported natural gas releases.[5] Emissions from trucks associated with UGS facilities are not captured in the facility-specific emissions inventories. In SCAQMD, facilities are required to estimate annual emissions, even if no emissions fees are due, and to pay corresponding emissions fees if they exceed the thresholds. Operation profiles by equipment are not required for reporting (SCAQMD, 2014).

Data Availability

As of June 2017, SCAQMD reported emissions for UGS facilities from 2000 through 2016. CARB reported data for criteria pollutants for UGS facilities from 1987-2016, while toxic air pollutants data were available from 1996 through 2016. Between March and June 2017, data were extracted from the SCAQMD and CARB facility reporting tools using Facility ID to identify UGS facilities. SCAQMD data were copied directly from online tables, and CARB data were downloaded in available Excel files. Publicly available data were included in this assessment for emissions from on-site stationary sources. Emissions from mobile sources (e.g., trucking) are not publicly available for each facility. Table 1.4-1 and Table 1.4-2 show emissions data availability for criteria pollutants and toxic air pollutants by UGS facility and by year. Note that this discussion pertains to emissions (rates) rather than concentrations, which are required to be measured at wellheads and attached pipelines by CARB regulations (CARB, 2017c) for use in detecting leakage rather than quantifying the leakage rate.

5. Personal Communication, South Coast Air Quality Management District (SCAQMD). June 13, 2017; Personal Communication, Colusa County Air Pollution Control District. June 26, 2017; Personal Communication, Yolo-Solano Air Quality Management District. June 13, 2017

Table 1.4-1. Criteria pollutant emissions data availability for UGS facilities in California. Data sources are specified when data are available from CARB or SCAQMD. Green = data available from one emissions inventory; red = no data available; yellow = data available from both CARB and SCAQMD; grey = site not in operation.

	FACILITY NAME												
YEAR	Aliso Canyon	Princeton Gas	Gill Ranch	Goleta	Honor Rancho	Lodi Gas	Kirby Hill	Los Medanos	McDonald Island	Montebello	Playa del Rey	Pleasant Creek	Wild Goose
2016	SCAQMD				SCAQMD					SCAQMD	SCAQMD		
2015	SCAQMD	CARB	CARB	CARB		CARB	CARB	CARB	CARB			CARB	CARB
2014		CARB	CARB	CARB		CARB	CARB	CARB	CARB			CARB	CARB
2013		CARB	CARB	CARB		CARB	CARB	CARB	CARB			CARB	CARB
2012		CARB	CARB	CARB		CARB	CARB	CARB	CARB			CARB	CARB
2011				CARB		CARB	CARB	CARB	CARB			CARB	CARB
2010				CARB		CARB	CARB	CARB	CARB			CARB	CARB
2009				CARB		CARB	CARB	CARB	CARB			CARB	CARB
2008				CARB		CARB	CARB	CARB	CARB			CARB	CARB
2007				CARB		CARB		CARB	CARB			CARB	CARB
2006				CARB		CARB		CARB	CARB			CARB	CARB
2005						CARB		CARB	CARB			CARB	CARB
2004						CARB		CARB	CARB			CARB	CARB
2003						CARB		CARB	CARB			CARB	
2002								CARB				CARB	
2001				CARB				CARB	CARB			CARB	
2000				CARB	CARB			CARB	CARB		CARB	CARB	
1999	CARB			CARB	CARB			CARB	CARB	CARB	CARB	CARB	
1998	CARB			CARB	CARB			CARB	CARB	CARB	CARB	CARB	
1997	CARB			CARB	CARB			CARB	CARB	CARB	CARB		
1996	CARB			CARB	CARB			CARB	CARB	CARB	CARB		
1995	CARB			CARB	CARB			CARB	CARB	CARB	CARB		
1993	CARB			CARB	CARB			CARB	CARB	CARB	CARB		
1990	CARB			CARB	CARB			CARB		CARB	CARB		
1987	CARB			CARB	CARB			CARB		CARB	CARB		

Table 1.4-2. Toxic air pollutant emission data availability for UGS facilities in California. Data sources are specified when data are available from California Air Resources Board (CARB) or South Coast Air Quality Management District (SCAQMD). Green = data available for one emissions inventory; red = no data available; yellow = data available from both CARB and SCAQMD; grey = site not in operation.

	FACILITY NAME												
YEAR	Aliso Canyon	Princeton Gas	Gill Ranch	Goleta	Honor Rancho	Lodi Gas	Kirby Hill	Los Medanos	McDonald Island	Montebello	Playa del Rey	Pleasant Creek	Wild Goose
2016	SCAQMD				SCAQMD					SCAQMD	SCAQMD		
2015	SCAQMD	CARB	CARB	CARB		CARB			CARB				CARB
2014		CARB	CARB	CARB		CARB	CARB	CARB	CARB				CARB
2013		CARB	CARB	CARB		CARB	CARB	CARB	CARB				CARB
2012		CARB	CARB	CARB		CARB	CARB	CARB	CARB				CARB
2011				CARB		CARB	CARB	CARB	CARB				CARB
2010				CARB		CARB	CARB	CARB	CARB				CARB
2009				CARB		CARB	CARB	CARB	CARB				CARB
2008				CARB		CARB	CARB	CARB	CARB				CARB
2007				CARB		CARB		CARB	CARB				CARB
2006				CARB		CARB		CARB	CARB				CARB
2005								CARB	CARB				CARB
2004								CARB					CARB
2003								CARB					
2002								CARB					
2001				CARB				CARB					
2000				CARB				CARB			CARB		
1999	CARB			CARB	CARB			CARB		CARB	CARB		
1998	CARB			CARB	CARB			CARB		CARB	CARB		
1997	CARB			CARB	CARB			CARB		CARB	CARB		
1996	CARB			CARB	CARB			CARB		CARB	CARB		

Data Discrepancies

Pollutant reporting varied by facility, by reporting agency, and by year. Certain facilities report only a few toxic air pollutants (e.g., Wild Goose, n < 2), while other facilities report a wider array of toxic air pollutants (e.g., Aliso Canyon, n > 30). These differences may be due to storage reservoir type (e.g., depleted oil vs. gas) or equipment used on site (e.g. gas-powered vs. electric-powered compressors); however, gas composition data and equipment-specific emissions reporting data are needed to explain differences between facilities. Data reported by SCAQMD and CARB for the same year and same facility also may differ (Table 1.4-3). Data vary in number of significant figures (decimal places) reported, due to the different way data are made publicly available (e.g., online tables, Excel files). Most emissions are determined using algorithms. This can be problematic, considering that *in situ* monitoring of Honor Rancho and McDonald Island methane emissions suggests that emissions are 2.5 to 5 times higher than what is reported in the inventories, as discussed in Section 1.5.

Table 1.4-3. Differences in reported annual emissions (pounds/year) between CARB and SCAQMD in 2015 for Playa del Rey, a UGS facility.

		Playa del Rey Emissions (pounds/year)	
CASRN	**Pollutant Name**	**CARB**	**SCAQMD**
7664-41-7	Ammonia	5110	239
71-43-2	Benzene	682	256
100-41-4	Ethylbenzene	129	78.1
110-54-3	Hexane	380	115

Data also vary by regulatory definition of pollutants. Lead is federally designated as a criteria pollutant, but is also listed as a toxic air contaminant (TAC) by the State of California. In the emissions inventories, lead is listed as a toxic air pollutant rather than a criteria pollutant. Methane, a potent greenhouse gas and the primary component of natural gas, is not required for reporting through the Air Toxics Hot Spots Program; however, methane was reported infrequently in the emissions inventories by a few UGS facilities. Pollutants are discussed as they are reported in the emissions inventories, as specified by the Air Toxics Hot Spots Program.

CARB and SCAQMD report pollutant ID, pollutant name, and annual mass emitted in tons or pounds. Pollutant ID aligns with Chemical Abstract Service Registry Number (CASRN), a unique numerical chemical identifier, unless the pollutant reported is a broad pollutant grouping (e.g., total organic gases (TOG), reactive organic gases (ROG)). Pollutant ID was available for all pollutants reported through emissions inventories, and was verified using Appendix 1.A of the Emission Inventory Criteria and Guidelines Report (CARB, 2007). CASRN were then assigned using pollutant ID or pollutant name using the Common Chemistry CAS Lookup tool maintained by the American Chemical Society (ACS, 2017).

Given data variability over time and at different UGS facilities, this assessment evaluates chemicals emitted from *any* UGS facility in California rather than focusing on facility-specific emissions. Facility-specific emissions summary tables can be found in Appendix 1.C.

Top Pollutants Historically Emitted by Mass

We examined pollutants historically emitted by mass across all UGS facilities in California from 1987 through 2015. Emissions data for 2016 were excluded, because data were unavailable for most UGS facilities. Emissions data were manually extracted from CARB through downloadable Excel files; if data were unavailable through CARB but were available through SCAQMD, data were extracted SCAQMD online tables. Criteria pollutant emissions reported by tons/year were converted to pounds/year to compare annual criteria and toxic air pollutant emissions. Pollutants were then sorted from highest to lowest median annual emissions years reported across all UGS facilities between 1987 and 2015. A summary of available emissions data including criteria pollutants, toxic air pollutants, and pollutant groupings is presented in Appendix 1.C, Table 1.C-1

Pollutant Groupings

Fourteen broad pollutant groupings were reported by UGS facilities between 1987 and 2015. These broad groupings include multiple unique chemicals. Broad pollutant groupings reported by UGS facilities include total organic gases (TOG), reactive organic gases (ROG), total suspended particles (TSP), volatile organic compounds (VOC), and polycyclic aromatic hydrocarbons (PAH). Many pollutant groupings may contain individual chemicals with health significance; for example, reactive organic gases include ozone precursors, which present a respiratory hazard. However, given that these pollutant groupings contain multiple pollutants, each with differing annual emissions and toxicity, these 14 pollutant groupings were excluded from further analysis.

Criteria Pollutants

Criteria pollutants are found across the United States and are known to harm human health and the environment. The Clean Air Act requires the U.S. EPA to set National Ambient Air Quality Standards (NAAQS) for six criteria pollutants: nitrogen oxides, sulfur oxides, particulate matter (PM), carbon monoxide, ground-level ozone, and lead (U.S. EPA, 2017a). However, lead is listed as a toxic air pollutant under the Air Toxics Hot Spots Program, and ground-level ozone is not required for reporting in emissions inventories, and therefore is not included in this analysis. Criteria pollutant emissions in the Air Toxics Hot Spots Program were reported in tons per year and were converted to pounds per year to compare emissions across all pollutants. Criteria pollutant emissions data are included from 1987 through 2015.

Toxic Air Pollutants

Toxic air pollutants are reported from 1996 through 2015. Toxic air pollutants include those listed in Appendix 1.A of the Emissions Inventory Criteria and Guidelines Report that present a chronic or acute threat to public health (CARB, 2007; CARB, 2016c). Methane emissions were reported under the toxic air-pollutant designation by a few UGS facilities, but given that methane is not required for reporting under the Air Toxics Hot Spots Program as a compound that presents a threat to public health, it was removed from further analysis.

Top Pollutants Historically Emitted by Mass

Ninety-eight compounds (criteria, toxic, and pollutant groupings) were reported as emitted from UGS facilities in California between 1987 and 2015. Pollutant groupings (e.g., total organic gases, reactive organic gases) and criteria pollutants (e.g., nitrogen oxides, sulfur oxides) were often ranked as the highest emitted compounds by mass. See full list in Appendix 1.C, Table 1.C-1. The health significance of these compounds is discussed in Section 1.4.6.

To identify and compare *specific* chemical compounds historically emitted by mass from UGS facilities in California, this analysis includes individual criteria and toxic air pollutants designated under the Air Toxics Hot Spots Program, but excludes broad chemical groupings. One criteria pollutant (carbon monoxide) and 82 toxic air pollutants were identified using classification by the Air Toxics Hot Spots Program. Compounds included polycyclic aromatic hydrocarbons (PAHs), nonmetals (excluding PAHs), and metals. The 83 pollutants, from here on referred to as "toxic air pollutants," were ranked by median annual emissions (pounds/year) that were calculated across UGS facilities and across all years of available data between 1987 and 2015. The top 25 toxic air pollutants historically reported by mass from UGS facilities are shown in Table 1.4-4. The health relevance of highly emitted compounds by mass is discussed in Section 1.4.6.

Table 1.4-4. Top 25 toxic air pollutants historically emitted from UGS facilities from 1987 to 2015, ranked by median annual emissions (pounds/year).

		Emissions (pounds/year)			
Chemical Name[1]	**CASRN[2]**	**Median**	**Min**	**Max**	**Toxic Air Contaminant (TAC)**
Carbon monoxide	630-08-0	45,360	192	838,656	N
Formaldehyde	50-00-0	3,159	0.2	27,296	Y
Ammonia	7664-41-7	996	0.1	33,907	N
Acetaldehyde	75-07-0	392	0.0	4,499	Y
Hexane	110-54-3	250	0.2	7,638	Y
Propylene	115-07-1	245	7	9,608	N
Methanol	67-56-1	213	0.04	1,515	Y
Acrolein	107-02-8	206	0.02	2,833	Y
Toluene	108-88-3	198	0.002	2,246	Y
m-Xylene	108-38-3	190	0.2	801	Y
Benzene	71-43-2	171	0.04	1,970	Y
Xylenes[1]	1330-20-7	72	0.02	893	Y
1,2,4-Trimethylbenzene	95-63-6	69	0.3	325	N
1,3-Butadiene	106-99-0	57	0.004	244	Y
Perchloroethylene	127-18-4	51	24	277	Y
Propylene oxide	75-56-9	45	28	45	Y
Trichloroethylene	79-01-6	44	0.05	102	Y

1 Chemical grouping (xylenes) included for further analysis because it has health-based benchmark values established by federal and state agencies (Section 1.4.6).

2 Pollutant ID reported rather than CASRN.

		Emissions (pounds/year)			
Chemical Name[1]	**CASRN[2]**	**Median**	**Min**	**Max**	**Toxic Air Contaminant (TAC)**
Ethylene glycol	107-21-1	27	11	40	Y
Ethylbenzene	100-41-4	25	0.01	291	Y
Naphthalene	91-20-3	24	0.002	106	Y
2,2,4-Trimethylpentane	540-84-1	21	1	36	Y
Silica, crystalline	1175[2]	18.3	18	18	N
Biphenyl	92-52-4	17.8	5	31	Y
Diethylene glycol monobutyl ether	112-34-5	12.9	12.9	12.9	N
Phosphorus	7723-14-0	12.7	3	23	N

1 Chemical grouping (xylenes) included for further analysis because it has health-based benchmark values established by federal and state agencies (Section 1.4.6).

2 Pollutant ID reported rather than CASRN.

Carbon monoxide, ammonia, and formaldehyde are the highest emitted toxic air pollutants historically emitted from UGS facilities in California. This trend is evident for each year in which compounds are reported between 1987 to 2015 (data not shown). Compounds with median annual emissions in excess of 200 pounds per year include hexane, acetaldehyde, propylene, methanol, and acrolein. Based on reporting requirements through the Air Toxics Hot Spots Program, compounds required for reporting through emissions inventories are anticipated to have health relevance and are associated with adverse health outcomes. Additionally, many pollutants reported in the emissions inventories are toxic air contaminants (TACs), air pollutants that may cause or contribute to an increase in mortality or in serious illness, or that may pose a present or future hazard to human health (California Legislative Information, 2017; Table 1.4-4). However, annual emissions do not provide mass fraction information (concentration) or spatial and temporal detail, which are necessary to conduct a detailed exposure or risk assessment. In summary, we observe that reported emissions as shown in Table 1.4-4 indicate chemicals of concern associated with UGS and provide a basis for setting priorities, but do not provide information on the concentration of these species in the stored gas or other emissions associated with UGS. This key input is needed to assess whether exposures from routine and LOC events are within health guidelines or high enough to require intervention.

1.4.6 Toxicity of Chemical Components with Public Health Relevance

1.4.6.1 Approach to Ranking the Human Health Hazards of Chemicals Reported to Emissions Inventories

Chemical hazards stem from naturally occurring chemicals in storage reservoirs, chemicals used in maintenance for injection and production activities at UGS facilities, and chemicals used in the processing of stored gas to restore its quality as it is delivered to the transmission pipeline. Natural gas that is stored, processed, and distributed from UGS facilities contains various chemical compounds, a number of which are associated with adverse health outcomes.

This section uses a bottom-up approach to explore chemical hazards associated with UGS in California. Given data availability and limitations, this approach focuses on chemical *hazards* that are likely to cause harm, rather than focusing on *risk*, the probability of a hazard to cause health harm (see Section 1.4.3).

For 83 individual pollutants reported as emitted by UGS facilities in California (including, but not limited to those listed in Table 1.4-4), we evaluate chemical hazards by (1) using annual mass emitted and *chronic* toxicity-weights to identify priority chemicals for future monitoring and risk assessment considerations; and (2) identifying chemical-specific, human-health-relevant *acute* toxicity data, where available, and discuss priority acute toxicants associated with UGS in California, which may be particularly relevant when discussing large LOC events.

Toxicity-Based Emissions Ranking Approach

In addition to evaluating mass of emissions from UGS facilities, it is important to also evaluate toxic potency of individual chemicals. Toxicity can be characterized as acute (short-term consequences from a single exposure or multiple exposures over a short period) or chronic (long-term consequences from continuous or repeated exposures over a longer period). Because of the significant number of chemical combinations required and lack of toxicological studies for most combinations, it was not feasible for us to evaluate the potential synergistic hazards with multiple pollutants. Even with high emissions and elevated toxicity, an exposure pathway is required to bring a compound into contact with the human receptor for an adverse effect to occur.

As mentioned previously, publicly available annual emissions data do not include spatial or temporal detail (such as emissions rates or mass fraction) to allow for a fully quantitative exposure or risk assessment. Instead, we use chemical-specific chronic (non-cancer and cancer) toxicity weights and acute toxicity health-based benchmarks established based on inhalation exposure. The ultimate goal of this assessment is to discuss different elements that relate to increasing hazard posed by chemicals associated with UGS in California.

1.4.6.2 Toxic Hazard Assessment for Chronic Non-cancer and Cancer Effects

Toxicity-weighted emission scores account for chemical-specific toxicity and size of releases. Toxicity-weighted emissions scores were calculated using median annual emissions data (pounds/year) from publicly available emissions inventories in California (see Section 1.4.4.) and EPA's Inhalation Toxicity Scores for individual chemicals (see Equation 1). U.S. EPA's Inhalation Toxicity Scores are chemical-specific toxicity weights for chronic non-cancer and cancer endpoints (U.S. EPA, 2017b). For more information about toxicity weights, see Appendix 1.C.

Equation 1:

Median annual emissions (pounds/year) × *EPA Inhalation Toxicity Score*[6] = *Toxicity-weighted emissions score*

1.4.6.3 Toxic Hazard Assessment for Acute Non-cancer Effects

This assessment includes evaluation of acute toxicity information for non-cancer health endpoints. Inhalation was the primary route of exposure assessed. To evaluate chemicals according to health hazard characteristics, regulatory and health-based values from state and federal sources were compiled and converted to same units of measurement (ug/m^3). When assessing toxic hazard, chemicals with observed effects at the lowest concentration pose greater hazard. For chemicals with multiple acute regulatory or health-based values, the minimum or most conservative value was chosen as the screening criterion for that chemical.

Acute Screening Values for the Inhalation Route

Regulatory and health-based values for acute toxicity for non-cancer effects include the following:

1. Office of Environmental Health Hazard Assessment-derived (OEHHA) acute Reference Exposure Levels (RELs)

2. Agency for Toxic Substances and Disease Registry (ATSDR) acute Minimum Risk Levels (MRLs)

Acute screening criteria included OEHHA acute reference exposure levels (RELs) and ATSDR acute minimum risk levels (MRLs). Acute RELs are airborne concentrations of a chemical that are not anticipated to result in adverse non-cancer health effects for short exposure durations in the general population, including sensitive subpopulations (OEHHA, 2016). Acute MRLs are estimates of the daily human exposure to a hazardous substance that is likely to be without appreciable risk of adverse non-cancer health effects over a short duration of exposure (1 – 14 days) (ATSDR, 2017a). To compare values, MRLs were converted to the same unit as RELs, micrograms per cubic meter (ug/m^3). MRLs reported as ppm were first multiplied by chemical-specific molecular weight and then divided by 24.25, taking into account standard temperature and pressure. MRLs were then multiplied by 1,000 to convert from mg/m^3 to ug/m^3.

6. For chemicals with both non-cancer and cancer toxicity weights, the highest (most conservative) toxicity weight was reflected in the Inhalation Toxicity Score. Non-cancer and cancer toxicity weights and chemical ranking specific to UGS facilities are included in Appendix 1.C, Table 1.B-2.

If multiple acute benchmarks were available, the most restrictive was chosen as the respective screening value. Chemical-specific hazard screening values for acute (non-cancer) endpoints are listed in Table 1.4-7. Methods are adapted from California Council on Science and Technology (CCST, 2015a).

1.4.6.4 Results of Human-Health Hazard Assessment of Chemicals Emitted from UGS Facilities

In this section, we provide results of toxicity-based emissions ranking for chemicals reported to emissions inventories from UGS facilities.

1.4.6.4.1 Chemical Hazards Associated with UGS Facility Emissions

Acute (non-cancer) screening criteria availability and chronic (non-cancer and cancer) toxicity weight availability are presented in detail in Table 1.4-5. Of the 83 compounds identified in the emissions inventories, 34 compounds (41%) had acute toxicity health benchmarks and 73 compounds (88%) had chronic (non-cancer or cancer) toxicity weights. Thirty (36%) compounds had identifiable CASRN and both available acute screening criteria and chronic toxicity weights. Six (7%) compounds with unique chemical identifiers lacked both acute screening criteria and chronic toxicity weights.

In cases where multiple acute, multiple chronic, or multiple cancer screening values were available for a particular chemical, the most restrictive one was chosen as the hazard screening criteria. Acute, chronic, and cancer screening criteria calculations are presented in Appendix 1.C, Tables 1.C-2., 1.C-3., and 1.C-4. Hazard screening criteria can be used to rank chemicals according to their human health hazard potential. For risk-based calculations and risk-ranking, original health-based criteria (e.g., REL, MRL) should be used in combination with the appropriate risk assessment exposure metrics.

Table 1.4-5. Availability of information to characterize toxicity of chemicals reported in emissions inventories (n = 83).

Number of chemicals	Acute screening criteria	Chronic (non-cancer and cancer) toxicity-weights
30 (36%)	Available	Available
4 (5%)	Available	Unavailable
43 (52%)	Unavailable	Available
6 (7%)	Unavailable	Unavailable

1.4.6.4.2 Chronic Toxicity and Carcinogenicity Screening

A total of 73 compounds (88%) had Inhalation Toxicity Scores for chronic non-cancer and/or cancer hazards, including 18 PAHs, 45 nonmetals, and 10 metals. Ten compounds (12%) lacked toxicity-weights. These compounds included: 2,2,4-trimethylpetnane; carbon monoxide; diesel engine exhaust, particulate matter; diethylene glycol monobutyl ether; dipropylene glycol methyl ether; ethylene glycol monobutyl ether; nitrogen oxide; silica, crystalline; sodium hydroxide; and methylene chloride.

Toxicity-weighted emission scores accounting for chemical-specific toxicity and size of releases are reported in Table 1.4-6. Chronic toxicity weights are detailed in Appendix 1.C, Table 1.C-2. Chemicals with the highest calculated toxicity-weighted emissions from UGS facilities in California include formaldehyde, acrolein, ethylene dibromide, 1,3-butadiene, benzene, acetaldehyde, tetrachloroethane, trichloroethylene. Chronic non-cancer and cancer health effects associated with these compounds are discussed in Section 1.4.6.4.4.

1.4.6.4.3 Acute Toxicity Screening

Thirty-four (34) chemicals (41%) had established acute hazard screening values, including 30 nonmetals (excluding PAHs) and 4 metals (Table 1.4-7). For chemicals with multiple acute screening values, the most restrictive (lowest) value was chosen as the chemical-specific hazard screening criteria. Acute screening values and screening criteria are detailed in Appendix 1.C, Table 1.C-3. Acute toxicity (non-cancer) screening criteria are shown in Table 1.4-7. Compounds with low health benchmarks for acute toxicity and high median annual emissions from UGS facilities are discussed in Section 1.4.6.4.4.

Table 1.4-6. Chronic (noncancer and cancer) toxicity-weighted emissions from UGS facilities in California between 1987 and 2015. Compounds are listed by most hazardous to least hazardous based on chemical-specific median annual emissions and toxicity weights.

		Inhalation Toxicity Score		
Chemical Name[1,2]	**CASRN**	**Median annual emissions (pounds/year)**	**Toxicity Weights**	**Toxicity-weighted emissions**
Formaldehyde	50-00-0	3159	46,000	145,310,537
Acrolein	107-02-8	206	180,000	37,066,065
Ethylene dibromide	106-93-4	4	2,100,000	8,428,974
1,3-Butadiene	106-99-0	57	110,000	6,236,313
Benzene	71-43-2	171	28,000	4,791,412
2-Methyl naphthalene[1]	91-57-6	6	710,000	4,433,950
Acetaldehyde	75-07-0	392	7,900	3,093,610
Phenanthrene[1]	85-01-8	2	710,000	1,388,760
Tetrachloroethane	79-34-5	4	210,000	760,790
Trichloroethylene	79-01-6	44	15,000	657,075
Phosphorus	7723-14-0	13	50,000	636,875
Acenaphthylene[1]	208-96-8	0.9	710,000	623,337
Propylene oxide	75-56-9	45	13,000	579,800
Fluorene[1]	86-73-7	0.8	710,000	579,379
Chromium[2]	7440-47-3	0.008	43,000,000	325,080
Asbestos	1332-21-4	0.002	165,000,000	324,225
Naphthalene	91-20-3	24	12,000	285,914
Ethylene dichloride	107-06-2	3	93,000	251,633
Chloroform	67-66-3	2	82,000	157,053
Pyrene[1]	129-00-0	0.2	710,000	138,969
Acenaphthene[1]	83-32-9	0.2	710,000	127,729
Fluoranthene[1]	206-44-0	0.2	710,000	113,423
Carbon tetrachloride	56-23-5	3	21,000	69,689
Chrysene[1]	218-01-9	0.09	710,000	63,190
Vinyl chloride	75-01-4	2	31,000	48,999
Perchloroethylene	127-18-4	51	930	47,695
1,2,4-Trimethylbenzene	95-63-6	69	580	39,750
Benzo[e]pyrene[1]	192-97-2	0.06	710,000	39,663
Benzo[a]anthracene[1]	56-55-3	0.06	710,000	39,612
1,3-Dichloropropene	542-75-6	2.6	14,000	36,384

1 Toxicity-weight for polycyclic aromatic hydrocarbon was applied as chemical-specific toxicity weight was unavailable. These values may over- or under-represent toxic potency of a specific polycyclic aromatic hydrocarbon.

2 Chromium is hexavalent; nonhexavalent chromium reported separately in emissions inventories, lacked toxicity weight information, and was therefore excluded from analysis.

Chemical Name[1,2]	CASRN	Inhalation Toxicity Score		
		Median annual emissions (pounds/year)	Toxicity Weights	Toxicity-weighted emissions
Ammonia	7664-41-7	996	35	34,874
Ethylbenzene	100-41-4	25	890	22,193
Arsenic	7440-38-2	0.001	15,000,000	17,865
Benzo[b]fluoranthene[1]	205-99-2	0.02	710,000	16,962
1,1,2-Trichloroethane	79-00-5	3	5,700	16,426
Biphenyl	92-52-4	18	800	14,271
Cadmium	7440-43-9	0.001	6,400,000	6,912
Xylene, m-	108-38-3	190	35	6,635
Nickel	7440-02-0	0.003	930,000	3,116
Xylenes	1330-20-7	72	35	2,522
1,2-Dichloropropane	78-87-5	2	880	2,145
Chlorine	7782-50-5	0.08	23,000	1,867
Hexane	110-54-3	250	5	1,252
Benzo(g,h,i)perylene	191-24-2	0.06	20,000	1,116
Beryllium[1]	7440-41-7	0.0001	8,600,000	784
Methylene chloride	75-09-2	10	36	361
1,1-Dichloroethane	75-34-3	0.6	570	328
Propylene	115-07-1	245	1.2	294
Indeno[1,2,3-cd]pyrene[1]	193-39-5	0.0004	710,000	288
Ethylene glycol	107-21-1	27	8.8	234
Lead	7439-92-1	0.01	23,000	207
Benzo(a)pyrene[1]	50-32-8	0.0003	710,000	198
Perylene[1]	198-55-0	0.0002	710,000	171
Benzo[k]fluoranthene[1]	207-08-9	0.0002	710,000	148
Toluene	108-88-3	198	0.7	139
Xylene, p-	106-42-3	2	35	78
Methanol	67-56-1	213	0.18	38
Phenol	108-95-2	2	18	36
Methyl tert-butyl ether	1634-04-4	0.4	93	35
Zinc	7440-66-6	0.3	100	26
Hydrogen sulfide	2148878	0.01	1,800	23
Manganese	7439-96-5	0.002	12,000	23
Hydrochloric acid	7647-01-0	0.09	180	17
Xylene, o-	95-47-6	0.4	35	15

1 Toxicity-weight for polycyclic aromatic hydrocarbon was applied as chemical-specific toxicity weight was unavailable. These values may over- or under-represent toxic potency of a specific polycyclic aromatic hydrocarbon.

2 Chromium is hexavalent; nonhexavalent chromium reported separately in emissions inventories, lacked toxicity weight information, and was therefore excluded from analysis.

Chemical Name[1,2]	CASRN	Inhalation Toxicity Score: Median annual emissions (pounds/year)	Toxicity Weights	Toxicity-weighted emissions
Mercury	7439-97-6	0.001	12,000	10
Styrene	100-42-5	2	3.5	5
Chlorobenzene	108-90-7	1	3.5	4
Copper	7440-50-8	0.002	1,500	3.4
1,1,1-Trichloroethane	71-55-6	1	0.7	1
Chlorodifluoromethane	75-45-6	10	0.07	1
Selenium	7782-49-2	0.001	180	0.2
Anthracene	120-12-7	0.03	3.3	0.1
Methyl ethyl ketone	78-93-3	0.02	0.7	0.01

1 Toxicity-weight for polycyclic aromatic hydrocarbon was applied as chemical-specific toxicity weight was unavailable. These values may over- or under-represent toxic potency of a specific polycyclic aromatic hydrocarbon.

2 Chromium is hexavalent; nonhexavalent chromium reported separately in emissions inventories, lacked toxicity weight information, and was therefore excluded from analysis.

Table 1.4-7. Acute non-cancer benchmarks for compounds reported in emissions inventories by UGS facilities in California between 1987 and 2015.

Pollutant Name	CASRN	Acute (ug/m³)	Acute Data Source	Acute Endpoint(s)	Median annual emissions (pounds/year)
Nonmetals					
1,1,1-Trichloroethane	71-55-6	6.80E+04	OEHHA	Neurological	1.1
1,3-Butadiene	106-99-0	6.60E+02	OEHHA	Developmental	57
Acetaldehyde	75-07-0	4.70E+02	OEHHA	Ocular; respiratory	392
Acrolein	107-02-8	2.50E+00	OEHHA	Ocular; respiratory	206
Ammonia	7664-41-7	1.18E+03	ATSDR	Respiratory	996
Benzene	71-43-2	2.70E+01	OEHHA	Developmental; immune; hematologic	171
Carbon monoxide	630-08-0	2.30E+04	OEHHA	Cardiovascular	45360
Carbon tetrachloride	56-23-5	1.90E+03	OEHHA	Alimentary; reproductive; developmental; neurological	3.3
Chlorine	7782-50-5	2.10E+02	OEHHA	Ocular, respiratory	0.081
Chloroform	67-66-3	1.50E+02	OEHHA	Reproductive/ developmental; respiratory; neurological	1.92
Ethylene glycol	107-21-1	2.00E+03	ATSDR	Respiratory	27

Pollutant Name	CASRN	Acute (ug/m³)	Acute Data Source	Acute Endpoint(s)	Median annual emissions (pounds/year)
Ethylene glycol monobutyl ether	111-76-2	4.46E+03	ATSDR	Hematological	2.17
Formaldehyde	50-00-0	4.91E+01	ATSDR	Respiratory	3159
Hydrogen chloride	7647-01-0	2.10E+03	OEHHA	Respiratory; ocular	0.094
Hydrogen sulfide	7783-06-4	4.20E+01	OEHHA	Neurological	0.013
m-Xylene	108-38-3	2.20E+04	OEHHA	Neurological; respiratory; ocular	190
Methanol	67-56-1	2.80E+04	OEHHA	Neurological	213
Methyl ethyl ketone	78-93-3	1.30E+04	OEHHA	Respiratory; ocular	0.017
Methyl tert-butyl ether	1634-04-4	7.21E+03	ATSDR	Neurological	0.38
Methylene chloride	75-09-2	2.08E+03	ATSDR	Neurological	10.04
o-Xylene	95-47-6	2.20E+04	OEHHA	Neurological; respiratory; ocular	0.43
p-Xylene	106-42-3	2.20E+04	OEHHA	Neurological; respiratory; ocular	2.23
Phenol	108-95-2	5.80E+03	OEHHA	Respiratory; ocular	2.02
Propylene oxide	75-56-9	3.10E+03	OEHHA	Respiratory; ocular; reproductive/ developmental	45
Sodium hydroxide	1310-73-2	8.00E+00	OEHHA	Respiratory; ocular; dermal	4.4
Styrene	100-42-5	2.10E+04	OEHHA	Respiratory; ocular; reproductive/ developmental	1.54
Perchloroethylene	127-18-4	4.07E+01	ATSDR	Neurological	51
Toluene	108-88-3	7.54E+03	ATSDR	Neurological	198
Vinyl chloride	75-01-4	1.80E+05	OEHHA	Neurological; respiratory; ocular	1.58
Xylenes	1330-20-7	8.68E+03	ATSDR	Neurological	72
Metals					
Arsenic	7440-38-2	2.00E-01	OEHHA	Developmental; cardiovascular; neurological	0.0012
Copper	7440-50-8	1.00E+02	OEHHA	Respiratory	0.0022
Mercury	7439-97-6	6.00E-01	OEHHA	Neurological; development	0.0008
Nickel	7440-02-0	2.00E-01	OEHHA	Immune	0.003

1.4.6.4.4 Discussion of Priority Compounds associated with UGS

Compounds with high emissions from UGS facilities are associated with acute and chronic (non-cancer and cancer) adverse health effects. Chronic toxicity-weighted emissions and acute hazard screening criteria are shown in Tables 1.4-6 and 1.4-7, respectively. Below we discuss (1) acute toxicants with low health benchmarks and high median annual emissions, and (2) chronic toxicants and carcinogens with high toxicity-weighted emissions.

Acute Toxicants

Carbon monoxide (CO) is a colorless, odorless gas that can be acutely toxic. It is the highest emitted compound from UGS facilities in California, and it is health-relevant for acute exposures. High concentrations of carbon monoxide can displace oxygen and cause simple asphyxiation. While displacement of oxygen is unlikely to occur outdoors, elevated CO concentrations can adversely impact those with heart disease, especially while exercising or under stress. Acute exposures to elevated CO may reduce oxygen to the heart, which can result in chest pain (angina) (U.S. EPA, 2016a).

Acute and Chronic Toxicants (non-cancer)

Both ammonia and acrolein are emitted in great quantities from UGS facilities and are health-relevant pollutants regarding acute and chronic toxicity. Ammonia is a colorless gas with a sharp odor that causes irritation upon direct contact, such as with the skin, eyes, respiratory, and digestive tracts. Chronic exposure to elevated concentrations of ammonia can impair respiratory function (ATSDR, 2004). Direct exposure to low concentrations of acrolein in air may cause irritation to the eyes, nasal cavity, and respiratory tract. In animals, acrolein has been found to damage the gastrointestinal lining, with the severity of effects dose-dependent (Faroon et al., 2008). Neither acrolein nor ammonia have been identified as carcinogens.

Chronic Toxicants (including known carcinogens)

Ethylene dibromide is a colorless liquid with a sweet odor that is not detectable at very low concentrations (ATSDR, 2014). It is extremely toxic, but chronic effects from ethylene dibromide exposure have not been well documented in humans. Animal studies show that chronic exposure to ethylene dibromide may result in toxic effects to the liver, kidney, and the testis. Limited data on men occupationally exposed to ethylene dibromide indicate that chronic exposure to ethylene dibromide can impair reproduction by damaging sperm. U.S. EPA classifies ethylene dibromide as a Group B2 probable human carcinogen, based on evidence from animal studies at various tumor sites (U.S. EPA, 2016b).

Trichloroethylene is a clear liquid with a sweet odor and is widely used in industrial degreasing operations (U.S. EPA, 2016c). Chronic inhalation exposure to trichloroethylene can adversely impact the central nervous system, causing dizziness, facial numbness, blurred vision, and nausea. In occupational settings, trichloroethylene exposure has been associated with autoimmune disease (sclerodema) (ATSDR, 2016). Trichloroethylene is a known human carcinogen, with strong associations observed between trichloroethylene exposure and kidney cancer in humans (National Toxicology Program, 2016).

Similar to trichloroethylene, tetrachloroethane is a clear liquid with a sweet odor and is used as a solvent (ATSDR, 2008a). Chronic exposure to tetrachloroethane can cause respiratory and eye irritation, as well as impacts to the central nervous system and liver. U.S. EPA has classified tetrachloroethane as a Group C possible human carcinogen for evidence of liver tumor formation in animal studies (U.S. EPA, 2016d).

Benzene, acetaldehyde, 1,3-butadiene, and formaldehyde are recognized as acute and chronic toxicants, known carcinogens, and highly emitted compounds from UGS facilities in California. Benzene is a colorless gas with a sweet odor. Acute exposures to benzene in air (10,000-20,000 ppm) can result in death. Lower concentrations (700-3,000 ppm) can cause dizziness, headaches, confusion, and unconsciousness. Chronic exposure to lower levels can impair the ability to form healthy blood cells, particularly in bone marrow. Long-term exposure to benzene is strongly associated with hematological cancers (leukemia) and multiple myeloma, which often forms tumors in the bone barrow. Benzene is recognized as a known carcinogen by the International Agency for Research on Cancer (IARC) (ATSDR, 2007).

Acute exposure to acetaldehyde can cause irritation of the eyes, skin, and respiratory tract, and depressed respiration. Carcinogenic effects from acetaldehyde exposure have been documented in animals via nasal tumors in rats and laryngeal tumors in hamsters (U.S. EPA, 2000). 1,3-Butadiene is a colorless gas that smells like gasoline and is a product of the incomplete combustion of hydrocarbons (National Institutes of Health, 2017). Acute inhalation exposures to 1,3-butadiene can cause respiratory and eye irritation, and chronic exposure has been associated with adverse impacts to the respiratory and cardiovascular system in animals (U.S. EPA, 2016e). 1,3-butadiene is known to be a human carcinogen, based on sufficient evidence of carcinogenicity from studies in humans, and is known to cause lymphatic and hematopoietic cancers (National Toxicology Program, 2016).

Formaldehyde has the highest toxicity-weighted emissions of toxic air pollutants associated with UGS facilities in California, and is known for acute and chronic toxicity and carcinogenicity. This aligns with default emission factor information, as formaldehyde is often the highest emitted compound from gas-fired compressor stations and other infrastructure associated with UGS; and also implies that extensive formaldehyde emissions are associated with routine operations, rather than off-normal events (SCAQMD, 2014). Acute exposures to formaldehyde can cause irritation of the eyes, nasal cavity, and throat. There is a well-established relationship between chronic workplace exposure to formaldehyde and cancers of the nose and throat. Formaldehyde is a known human carcinogen classified by IARC (ATSDR, 2008b).

Toxic substances not included in comparative hazard assessment

A few criteria pollutants were not included in this assessment because they lacked unique chemical identifiers. However, these compounds are among the highest emitted compounds from UGS facilities in California (see Appendix 1.C, Table 1.C-1) and are known to adversely impact human health.

Nitrogen oxides (NO_x) and sulfur oxides (SO_x) are highly reactive gases that can form from combustion of hydrocarbons. Acute exposure to both NO_x and SO_x can cause respiratory irritation. Long-term exposure to NO_x can result in respiratory diseases such as asthma; children, the elderly, and those who suffer from respiratory diseases are particularly sensitive to effects of both NO_x and SO_x Additionally, both NO_x and SO_x can react with chemicals in the air to form other health-harming air pollutants, including particulate matter.

Particulate matter (PM) is made up of microscopic solid or liquid droplets that can come directly from a source or result from complex reactions of chemicals in the atmosphere. The incredibly small size of these particles means that they can be inhaled into the respiratory tract and deep into the lungs, causing serious respiratory and cardiovascular health problems.

Ground-level ozone is formed from chemicals reaction between NO_x and volatile organic compounds (VOCs) in the presence of sunlight. Exposure to ozone can cause respiratory issues, especially for children, the elderly, and those with respiratory disease. (U.S. EPA, 2017a). We did not have sufficient data to assess potential for ground-level ozone formation from ozone precursors (such as alkanes) that could result in secondary ozone. The contribution of organic gas species both from normal operation and LOCs to ground-level ozone formation is a potentially important public health question that has not been addressed to date for the 2015 Aliso Canyon incident or for any other UGS facility.

Discussion and Data Limitations

As mentioned previously, there is inherent uncertainty and lack of spatial and temporal detail in emissions inventory reporting, which makes it difficult to determine resulting atmospheric concentrations and quantify public health risks. As such, this assessment examines potential hazards posed by chemicals emitted from any UGS facility in California.

Quality and quantity of available data limit this assessment. Median annual emissions estimates were calculated using all publicly available data between 1987 and 2015. However, operators are only required to update emissions estimates every four years. Therefore, some emissions data are repeated for multiple years. While 75 compounds (90%) identified in emissions inventories had established values for acute toxicity and/or chronic toxicity weights, 8 (10%), compounds with unique chemical identifiers lacked any toxicity information. Finally, this assessment is limited to compounds reported in emissions inventories. While the Air Toxics Hot Spots Program requires reporting for compounds with significant health relevance, it does not include compounds particularly relevant to UGS, including mercaptans (odorants), which are discussed in detail in Section 1.4.10.

Despite these limitations, this assessment identifies priority chemicals, including criteria and toxic air pollutants, associated with UGS in California, based on annual mass emitted and chemical toxicity. These results are important when discussing chronic exposures to nearby communities and workers from routine UGS operations, as well as acute to subchronic exposures during large LOC events.

1.4.7 Assessment of Nearby Populations at Increased Health Risk: Proximity Analysis and Air Dispersion Modeling

In Section 1.1, we characterized the wells at each of the 13 UGS facilities. In Section 1.2, we discussed the subsurface migration pathways through which gas in UGS facilities can be emitted to the atmosphere. In this section, we use these data to evaluate nearby populations and their demographics that are at potential risk of exposures to air pollutant emissions and potential explosions from the California UGS facilities.

This section is broken into two primary parts: (1) A proximity analysis of populations in close proximity to UGS facilities in California; and (2) an assessment of air dispersion modeling and the populations that are at highest risk given average meteorological conditions, (e.g. wind direction, wind speed, and atmospheric mixing characteristics).

1.4.7.1 Proximity Analysis of UGS Facilities and Human Populations

1.4.7.1.1 Approach to Analysis of UGS Facilities and Potential Risk to Human Populations

Here we provide an overview of our approach to the analysis of populations in proximity and at varying likelihoods of exposures to emissions of toxic air pollutants and potential explosions from UGS facilities (CPUC, 2010), especially during larger loss-of-containment events (see Section 1.4.10). In particular, we analyzed the proximity of infrastructure directly associated with UGS facilities, and of infrastructure with potential sub-surface connectivity to UGS infrastructure, to human populations and sensitive receptors including schools, daycare centers, elderly care facilities, etc. For our detailed methodology, please see Appendix 1.D. Figure 1.4-2 below illustrates the general location of all California UGS facilities along with the relative scale of their working-gas capacity in Bcf. The approach we take here has similarities to what has been considered in the California Environmental Quality Act (CEQA) impact assessment process. However, a review of CEQA reports posted on the CPUC site for the subject storage facilities reveals that, with the exception of the Princeton site, the CEQA impact assessments for natural gas storage facilities focused on compliance with emissions standards for permitted releases. At all sites that have CEQA reports, these emissions are assumed to have an insignificant impact on the health of adjacent communities, because they are in compliance with California Air Resources Board (CARB) standards. This resulted in a “negative declaration,” which does not initiate the need for a proximity assessment. In the case of the Princeton site, the CEQA report included a fire and explosion risk assessment that supported a finding regarding a safe buffer distance for adjacent nonoccupational populations.

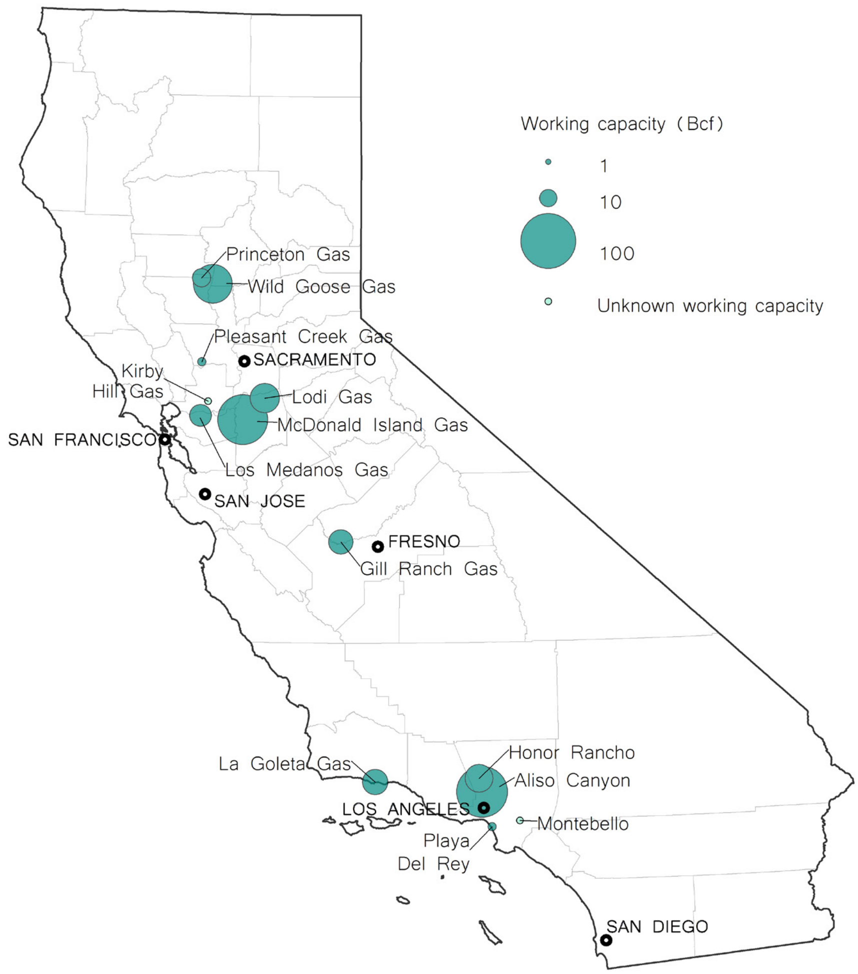


Figure 1.4-2. California underground natural gas storage wells depicted by working capacity in Bcf. These UGS facilities include 12 working gas storage facilities and one decommissioned facility, Montebello, with data that suggest that injections and withdrawals occurred at the facility up through 2016 (see Section 1.1.3).

We first divided wells based on their potential likelihood to serve as a conduit for gas leakage from the UGS storage facilities to the atmosphere. In making this division, we are considering the potential for leakage, which gives rise to two tiers. When we consider the potential inventory of toxic air emissions, it is also important to make a distinction between wells in depleted gas reservoirs and wells in depleted oil reservoirs, because the latter will have more trace constituents associated with oil residue (see Section 1.4.5).
For leakage potential, two tiers carried through our population proximity analysis include:

Tier 1 Wells: All wells located within an oil and/or gas pool used for gas storage and represents the most likely subsurface infrastructure subject to LOC to the atmosphere. We do not include wells that have been plugged.

Tier 2 Wells: All open (unplugged) wells located within the same *field area* as an oil and gas pool used for gas storage. The field area is a quasi-geological and administrative boundary used by DOGGR to delineate a given oil and/or gas accumulation. Field areas can represent multiple oil/gas pools. While the risk of subsurface migration of gas and other fluids from the pools used for gas storage to these wells in the greater field area is lower than the risk of emissions from Tier 1 wells (in the storage pool itself), historical data suggest that gas can certainly migrate in the subsurface over these geographical distances and across these geological strata.

UGS facilities are not always discrete facilities, and their surface administrative boundaries are not always a good predictor of where emission-prone infrastructure is located. More specifically, the administrative boundaries tend to cover a larger area than where the wells, compressors, and other infrastructure are located. Moreover, emission inventories do not provide insight into the spatial, temporal, or infrastructural distributions of emissions of air pollutants at UGS facilities. As such, it was necessary to assume that emissions could come from anywhere in the facility at any given time. In order to operationalize this assumption, we drew a contour line around the outermost wells of each facility to approximate the facility area, outside of which we would create our buffer distances for analysis.

Well Data Description and Approach

We obtained data for California wells from DOGGR. We intentionally used an older well dataset from 2015 (DOGGR, 2015) to reflect storage well conditions before the incident at Aliso Canyon that started in October 2015. We included all well data covering the 10-year time period up to dataset's end, which included years 2006–2015. We categorized wells as either "open" or "closed" to evaluate the likelihood of a well acting as a conduit for underground gas to reach the surface. This distinction is based on the presence or absence of an unplugged wellbore.

To examine the public health risks with a range of perspectives, we split the well dataset into two partially overlapping datasets that we labeled Tier 1 and Tier 2. The Tier 1 dataset is focused specifically on the storage pool around each underground gas storage facility, and it includes any open well that is located within a gas storage pool. The Tier 2 dataset represents a more conservative approach for public health and includes a broader set of criteria. This dataset includes all wells from Tier 1, and in addition it includes any open well that is located within the same field area as the gas storage pool.

Proximal Population Data Description and Approach

As a basis for understanding potential public health hazards attributable to UGS facilities, we evaluated the spatial relationships of gas storage pool and field area wells to the surrounding population, by evaluating resident counts and selecting sites considered to be "sensitive receptors." We examined the general population as well as vulnerable subgroups of the communities in proximity to underground gas storage facilities. One issue that we did not have resources to explore is that of encroachment—the historical rate of change of population proximity around a site. To assess encroachment requires detailed historical population mapping along with a chronology of when a facility was first put into operation and how its operations changed as the size and location of the population changed. Gathering this information would be time-consuming, and not particularly useful in informing the findings and recommendations of this study.

We obtained demographic information from the U.S. Census Bureau (2011) for the California general, youth, and elderly population to determine population counts for the following variables: total population, under five years of age, and 75 years and older. We also collected data for a series of point locations we are calling "sensitive receptors," which are places where vulnerable subgroups congregate. Schools and daycare centers for the youth population; residential elderly care facilities for the elderly population; and hospitals for the sick. These locations represent sites where a hazard may pose elevated risk to people, because of their vulnerability. While fetuses are in many instances among the most sensitive receptor to toxic exposures, we were unable to include this sub-population given the lack of access to a high-resolution, household-level pregnancy or birth dataset given the short timeline of this report. We do, however, recommend that questions of risks to fetuses posed by the 2015 Aliso Canyon incident be undertaken in the future.

Children and the elderly are two populations that are especially vulnerable. Children are still developing, and as such have respiratory systems that are particularly susceptible to chemical exposures (Webb et al., 2016)particulate matter . Children have much faster breathing rates than adults, thus they inhale a greater amount of air pollutants and dust in comparison to adults, resulting in proportionally higher exposures than adults in the same conditions would receive (Landrigan et al., 2004; Webb et al., 2016). Unlike adults, they have less ability to metabolize and excrete chemicals (Landrigan et al., 2004). Children have more years remaining in their lives, which increases their likelihood of chronic illnesses with long latency periods such as certain cancers (Sly and Carpenter, 2012). In addition, they have behavioral tendencies that could increase exposures, such as hand-to-mouth behavior, as well as active time outside, which not only increases exposures because of faster respiration due to activity, but in addition exposure is often higher outdoors (Landrigan et al., 2004; Webb et al., 2016).

Similar to children, elderly and sick populations generally have weaker immune systems than healthy adults (Risher et al., 2010). Pre-existing health conditions can hinder the body's ability to adapt and protect itself from potential effects of environmental exposures

(Risher et al., 2010; Hong, 2013). As part of normal aging, elderly individuals have had many more years of potential opportunities for environmental exposures, and they generally have a decreased ability to metabolize and excrete xenobiotics, including air pollutants related to gas storage (Risher et al., 2010; Hong, 2013).

Geographic Proximity Analysis Approach: 360-Degree Assessment

We created radial buffers at 0, 100, 200, 400, 600, 800 (~1/2 mile), 1000, 1600 (~1 mile), 2000, 5000, and 8000 (~5 miles) meters around the storage facility boundaries determined by the contour around the outermost wells, as described above.

The buffers used in this analysis are designed to encompass populations within various proximities to natural gas storage infrastructure and associated possible emissions, with the assumption that exposure to emissions will be the highest at the 0 m buffer and will continue at decreasing exposures through the remaining buffers as distance from facility increases. The 0 m buffer is the same thing as the storage facility boundary. This assumption is supported by analysis of resident complaint calls summarized by the Los Angeles County Department of Public Health (LACDPH) in response to the Aliso Canyon incident. This analysis found that the likelihood of reported health symptoms, including headache, nausea, nosebleeds, and respiratory problems, among other symptoms, was substantially greater for residents that lived ≤3 miles from the gas leak (55.8% of complaints), compared with residents that lived >5 miles from the gas leak (16.8% of complaints) (LACDPH, 2016c; see Section 1.4.10). For risk in particular of wells sustaining subsurface blowouts with breaching to surface, there is evidence that the locations of emission points to atmosphere (surface fractures or craters) typically do not exceed a distance of 600 m from the wellhead (Jordan and Benson, 2009).

For a complete description of our methods and approach to the spatial proximity analysis, please see Appendix 1.D.

1.4.7.1.2 Results of Analysis of UGS Facilities and Potential Risk to Human Populations

Our assessments of population and sensitive receptor counts between the Tier 1 (UGS facility wells) and Tier 2 (wells in the field area where each UGS facility is located) analyses are very similar. The difference in total population between the Tier 1 and Tier 2 results at the 1,600 m buffer distance is less than 10 people at 11 out of 13 sites. Los Medanos Gas had a population increase of an estimated 193 people, or a 26.1% increase, but this percentage is so high only because the original population count was quite small at 740 people. Montebello is the only gas storage facility with a substantial population change between the Tier 1 and Tier 2 well datasets. The population living within 1,600 m increased 12.7%, from 41,170 to 46,399 people. Given the similarity in results between the UGS well and the greater field area well analysis (Tier 1 and Tier 2), the remainder of the results for this section will focus exclusively on the Tier 1 (UGS well) analysis results.

As noted in Table 1.4-8, across California, we estimate that 1,864,775 people live within 8,000 m (~5 miles) of a UGS facility. Population counts differ substantially across gas storage facilities, with a minimum of 116 people at Wild Goose Gas and a maximum of 734,988 people at Montebello living within the 8,000 m buffer distance.

Approximately 115,125 children under the age of five live within 8,000 m of an active UGS facility. There are an estimated 1,358 daycare centers within this distance, with 1,337 currently open and 21 pending. In addition, there are 556 schools within this distance, all currently open, which enroll 292,935 children. An estimated 103,085 adults age 75 and older also live within 8,000 m of an UGS facility. There are also 359 residential elderly care facilities within this buffer distance, with 326 of them currently open and 33 pending (Table 1.4-8). Unlike the small buffers, the 8,000 m buffers overlap for two pairs of UGS facilities, creating populations that are within the buffers of two facilities in the case of Wild Goose Gas and Princeton, and also at Aliso Canyon and Honor Rancho. Population and sensitive receptor counts in Table 1.4-9 represent the populations in relation specifically on a UGS facility-by-facility basis; therefore, the same people and sensitive receptors may be counted more than once. In Table 1.4-8, this is remedied in a sum over all UGS facilities, where each person and sensitive receptor is only counted once. This explains why a sum of counts at each UGS facility does not equal the 8,000 m buffer sum over all UGS facilities.

Table 1.4-8. Summed population and sensitive receptor counts in proximity to underground storage sites in California, by buffer distance.

Distance From any UGS Well (meters)	Number of Residents	Under 5	Age 75 and Older	Number of Open Schools	Number of Children Enrolled in School	Number of Open Daycare Centers	Number of Open Elderly Care Facilities	Number of Hospitals
0	5,585	257	356	0	0	1	0	0
100	8,179	408	542	0	0	1	0	0
200	11,443	568	788	3	1,046	5	1	0
400	18,385	876	1,434	4	1,448	7	2	0
600	28,158	1,308	2,058	9	3,699	18	2	0
800 (1/2 mile)	40,503	1,843	2,704	12	5,435	29	2	0
1,000	54,127	2,597	3,458	17	9,974	35	2	1
1,600 (1 mile)	113,721	5,522	6,278	32	23,035	64	3	2
2,000	161,367	8,051	8,467	42	28,868	89	3	3
5,000	743,678	42,543	43,323	213	117,406	516	109	8
8,000	1,864,775	115,124	103,085	556	292,935	1,337	326	23

Table 1.4-9. Population and sensitive receptor counts for the 8,000 m (~5 mile) buffer, by underground storage site; N/A = data not available.

Underground Storage Facility	Working capacity (Bcf)	Number of Residents	Under 5	Age 75 and Older	Number of Open Schools	Number of Children Enrolled in School	Number of Open Daycare Facilities	Number of Open Elderly Care Facilities	Number of Hospitals
Aliso Canyon	86	232,202	12,502	14,962	77	48,000	183	93	2
Gill Ranch	20	545	55	18	0	0	0	0	0
Honor Rancho	26	156,688	9,495	4,963	45	35,369	105	52	1
Kirby Hill	N/A	291	11	14	0	0	0	0	0
La Goleta	21	94,421	3,734	6,719	26	12,132	74	39	3
Lodi Gas	29	24,114	1,625	1,595	9	2,851	10	2	0
Los Medanos	16	139,902	9,981	6,457	43	1,551	112	60	2
McDonald Island	82	646	51	17	0	0	0	0	0
Montebello	N/A	734,877	51,768	42,119	198	117,402	437	17	10
Playa del Rey	2	493,459	26,787	27,065	158	65,306	420	69	5
Pleasant Creek	2	8,270	522	342	4	0	9	0	0
Princeton	11	642	30	47	2	169	0	0	0
Wild Goose	50	116	4	6	0	0	0	0	0

In our examination of the association between working gas capacity and population counts for each underground gas storage facility, we found that there is not a strong relationship between population size and facility capacity. As noted in Table 1.4-9, Aliso Canyon, McDonald Island, and Wild Goose are the three facilities with the largest working capacities, at 86, 82, and 50 Bcf, respectively. Of these, both McDonald Island and Wild Goose are located in remote, low-population-density areas with a very small number of adjacent residents. In contrast, Aliso Canyon has a substantial proximal population and ranks 3rd of the 13 underground gas storage facilities in California including Montebello when comparing population at the 8,000 m buffer distance. Playa del Rey is located in an urban area on the coast and has the 2nd highest proximal population with greater than 400,000 people living within 8,000 m of the site, and it is tied with Pleasant Creek as the lowest working gas capacity UGS facility in California (2 Bcf). Montebello is the facility with the largest proximal population; however, the working capacity of this facility is unknown. The Montebello facility represents a unique case among the California UGS facilities, in that there are discrepancies in its regulatory records indicating whether the facility is administratively considered an operating gas storage facility, as discussed in Section 1.1 of this report.

There are populations that live directly above UGS pools, and these populations are captured under our analysis of the 0 m buffer. People living within this area are at greater risk of exposures to emissions of toxic air pollutants and potential explosions from surface and subsurface UGS facility infrastructure than populations located outside of the gas storage pool boundary. As seen in Table 1.4-10, there are 5,585 people living within this 0 m buffer distance of a UGS facility, with populations at seven of the 13 UGS facilities. Out of the total population living immediately above a gas storage pool, 258 are under age 5, and an additional 356 are age 75 and older, representing two population groups that are disproportionately vulnerable to environmental hazards. While four storage facilities have fewer than 100 people living within the boundary of the gas storage pool, one site (Lodi Gas) has 242 people, and two sites (Playa del Rey and Montebello) each have over 1,000 people living within its gas storage area. There are no schools, daycare facilities, residential elderly care facilities, or hospitals indicated in the data for these areas.

Table 1.4-10. Population counts for the 0 m buffer, by underground storage site.

Underground Storage Facility	Number of Residents	Under Age 5	Age 75 and Older
Playa del Rey	3,782	165	193
Montebello	1,470	75	149
Lodi	242	12	9
La Goleta	39	1	3
Aliso Canyon	25	1	2
McDonald Island	24	4	0
Princeton	3	0	0
TOTAL	**5,885**	**258**	**356**

Population Density

Similar to population counts, there is a wide range of population densities among the 13 (including Montebello) storage facilities in California. We calculated population densities for each combination of buffer distance (11 buffers) and UGS facility (13 facilities), providing 143 combinations. We categorized the population density values into five groupings, with category breaks chosen based on examination of residential land-cover patterns using aerial orthoimagery. The population density category breaks are as follows:

- 0 people per square kilometer (km^2) represents a population density of "None";
- >0 – 20 people/km^2 is categorized as "Very low";
- >20 – 100 people/km^2 is categorized as "Low";
- >100 - <1,000 people/km^2 is categorized as "Medium," and
- >1,000 – <5,000 people/km^2 is categorized as "High."

To provide context, areas categorized as "None" and "Very low" are primarily undeveloped, agricultural, industrial, or water (ocean) areas; and "High" are urban areas with a large ratio of residential land. "Low" and "Medium" areas are typically a mixture of undeveloped or agricultural land and residential areas, with expectedly lower or higher ratios of residential land, respectively.

Out of the 143 storage facility buffer combinations, 11 fall into the None, 69 in the Very Low, 20 in the Low, 19 in the Medium, and 22 in the High categories. With this categorization, 80 out of 143 storage facility buffer combinations (55.9%) have a population density of ≤100 people/km^2, indicating that they are located in very rural areas. Of these, 55 come from the 11 buffers of the McDonald Island, Princeton, Kirby Hill, Gill Ranch, and Wild Goose facilities, indicating that these five UGS facilities may have a lower relative hazard compared to more population-dense areas. Population density at the Kirby Hill Gas facility is shown in Figure 1.4-3. The 15.4% in the high population density category are in very urban areas, representing all 11 buffers around both the Montebello and Playa del Rey facilities, located in the Los Angeles Basin. Population density around the Montebello facility is shown in Figure 1.4-4. The buffers around the remaining storage facilities vary in their population density, ranging from medium to no population density. La Goleta has more buffers in the medium population density range, while Honor Rancho, Aliso Canyon, Los Medanos, Lodi, and Pleasant Creek have more buffers located within the low and very low population density ranges.

There are generalizations we can make about trends in population density between the northern and southern California UGS facilities. When the facilities are ranked by population density over all buffers, the five UGS facilities in the greater Los Angeles area in southern California rank one through five, indicating the greatest population densities out of the 13 storage facilities (includes Montebello). Montebello and Playa del Rey, the two facilities located in urban areas, are located in southern California. La Goleta, Honor Rancho, and Aliso Canyon have very low to low population densities at the smallest buffers, but as buffer distance increases, population density also increases into the “medium” range, as the buffers encroach into the urban areas in the greater Los Angeles area. In contrast, all UGS facilities north of the greater Los Angeles area have lower proximal population densities: 80.6% of the buffers in northern California are categorized as “none” or “very low,” indicating either an absence of people (12.5%) or a population density of less than 20 people per square km (68.2%).

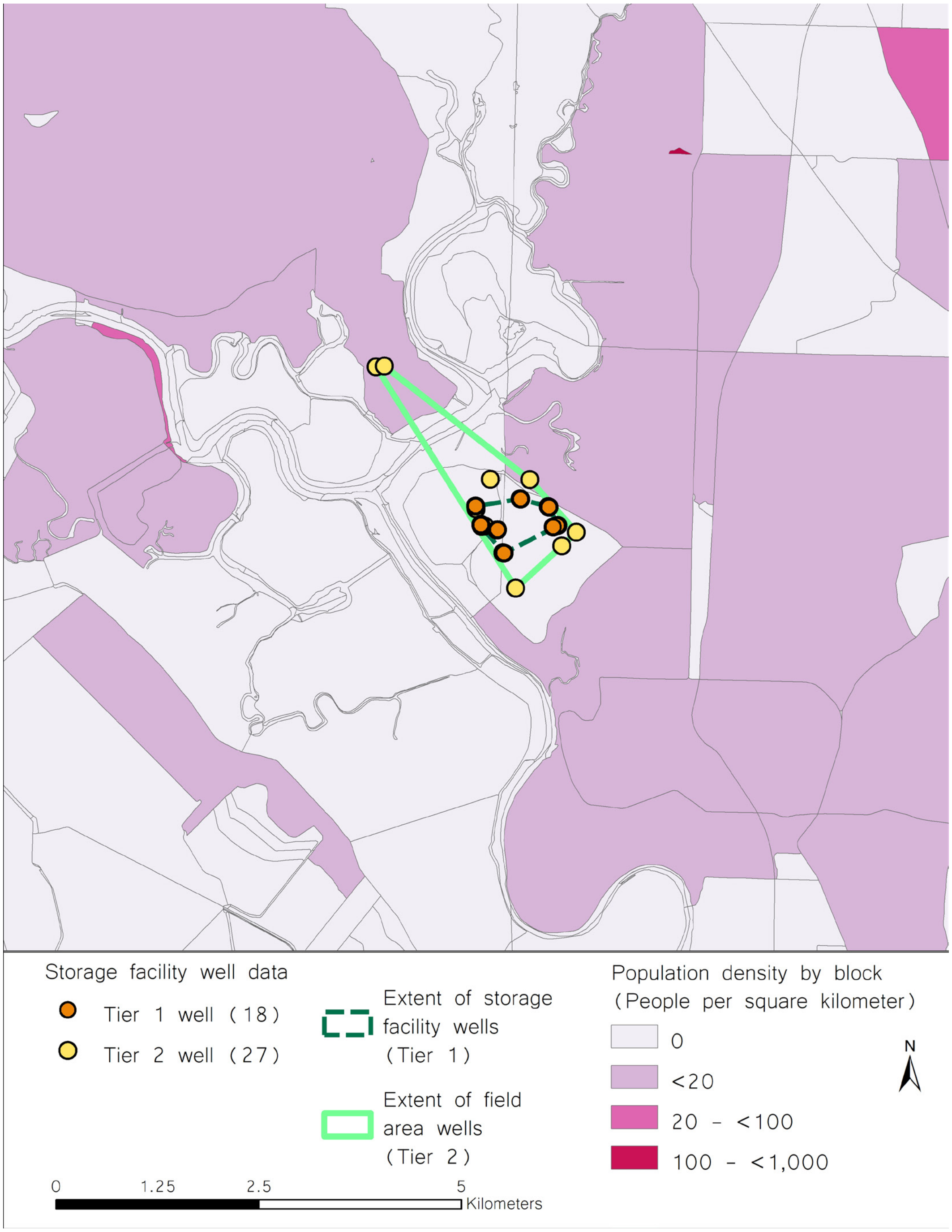


Figure 1.4-3. Population density measured in people per square kilometer around the Kirby Hill UGS facility.

Figure 1.4-4. Population density measured in people per square kilometer around the Montebello UGS facility.

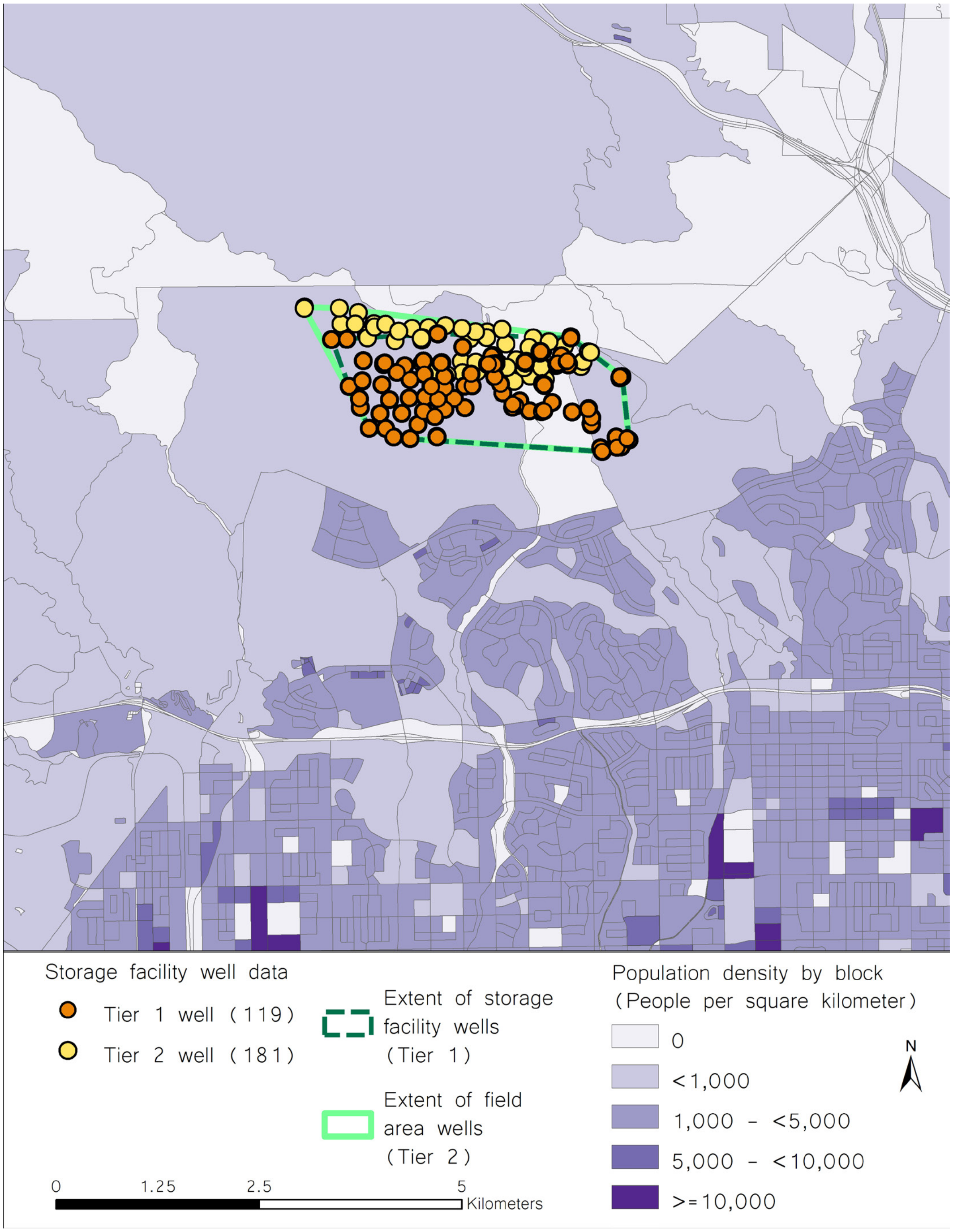


Figure 1.4-5. Population density measured in people per square kilometer around the Aliso Canyon UGS facility.

As a general rule, the smaller buffers, including 800 m and smaller, are more frequently located in the two lowest population density categories, indicating 100 or fewer people/km^2, while the likelihood of a buffer being located in a higher population density area increases as buffer size increases. Therefore, in general, populations directly adjacent to underground gas storage facilities tend to be more rural, while populations farther out (while still in the general vicinity of gas storage facilities) have a greater likelihood of being urban or suburban.

1.4.7.2 Air-Dispersion Modeling for UGS Emissions Health Assessment

In order to assess the potential for community exposures, we rely on air-dispersion modeling applied to each of the storage sites. These models are useful for describing how a known emission rate translates into air concentrations as a function of distance and radial location. However, making accurate concentration estimates requires a knowledge of emissions inventories and rates, and knowledge of atmospheric conditions—including wind speed and direction and atmospheric turbulence. In the absence of reliable emissions data (as noted earlier in Section 1.4.5), we used normalized concentration/emission ratios to determine the relative dilution of toxic air pollutants emitted by the UGS facilities into the atmosphere and transported by wind to nearby communities. We follow the approach to air-dispersion modeling that is introduced in Section 1.2 and described in more detail in Appendix 1.B.

Because we have very limited information on the quantities and chemical composition of emissions at UGS sites, we rely on bottom-up approaches that employ empirical emission factors to estimate emission inventories. These approaches do not provide the spatially and temporally varying emission inventory data that are critical for estimating downwind consequences of leaks from individual UGS sites. For instance—as described earlier in this section on the emission inventories—emissions reporting to air districts and CARB are not specific as to *where* the emissions originate from in the facility, and *which infrastructure* are the sources of any given emission.

Lack of temporal and spatially varying emissions data and lack of reliable meteorological data make it difficult to accurately estimate the concentrations and dispersion of gas leakage from UGS facilities. This finding means that continuous methane monitoring technology (with trigger sampling for toxic air pollutants) should be deployed at each UGS facility to provide reliable spatially and temporally varying data for analysis. On-site weather stations should be installed at each UGS facility following National Weather Service (NWS) guidelines to provide accurate and timely information during a release event.

1.4.7.3 Approach to Air-Dispersion Modeling

In this section, the methodology for estimating downwind concentrations due to a leak from a UGS facility is described. We present the air-dispersion results in terms of the ratio of downwind concentration (C) divided by the leakage flow rate (Q). This is because the concentrations depend on the emissions rate, and the emission rate is not known *a priori*.

The ratio of downwind concentration and the emission rate is commonly referred to as the C/Q ratio in the atmospheric dispersion literature. Dimensions of C/Q are L^{-3} t with common units m^{-3} s.

Meteorological data were collected over a period of one year (August 15, 2015–August 15, 2016) for each of the 13 UGS facilities in California (discussed in detail in Appendix 1.B). A unit emission rate was assumed at each well of the storage facility and was assumed constant in time for the entire period. The emission rates were combined with meteorological data (including wind speed, wind direction, shortwave incoming radiation, cloud cover) to estimate the downwind concentration, using the Gaussian Plume air dispersion model. The downwind concentrations were computed over a 10 km radius centered on the source, with a spatial resolution of 100 m. To account for the spatial distribution of the source, all the active wells within a storage facility were considered as point sources. The resulting concentration field was then normalized by the total emission rate from the facility to obtain the C/Q ratio.

The C/Q ratio can be used to compute the downwind concentration by multiplying an emission rate from the UGS facility with the C/Q ratio. For example, if the emission rate was 16 kilograms/second (kg/s) and the C/Q ratio was 44×10^{-9} m^{-3} s, then the downwind concentration would be computed as 16 kg/s $\times$ 44×10^{-9} m^{-3} s = 704 ug/m^3.

Table 1.4-11 shows the 13 underground storage facilities (including Montebello) considered in this work, along with the location, capacity, reservoir type, area, and number of active wells.

Table 1.4-11. Characterization of Underground Gas Storage Facility location, capacity, type and other attributes in California.

Storage Facility	Latitude, Longitude	Capacity (Bcf)	Reservoir type	Field Area (km²)	Active Wells	County
Aliso Canyon	34.313, -118.558	86.2	Oil	13.75	141	Los Angeles
Gill Ranch Gas	36.793, -120.250	20.0	Gas	25.90	26	Madera
Honor Rancho	34.456, -118.598	27.0	Oil	9.27	51	Los Angeles
Kirby Hill Gas	38.169, -121.918	15.0	Gas	17.15	23	Solano
La Goleta Gas	34.421, -119.826	19.7	Gas	4.95	19	Santa Barbara
Lodi Gas	38.201, -121.208	17.0	Gas	19.50	24	San Joaquin
Los Medanos Gas	38.027, -122.021	17.95	Gas	18.18	23	Contra Costa
McDonald Island Gas	37.994, -121.480	82.0	Gas	46.75	88	San Joaquin
Montebello	34.025, -118.094	---	Oil	15.07	211	Los Angeles
Playa del Rey	33.970, -118.446	2.4	Oil	7.46	49	Los Angeles
Pleasant Creek Gas	38.553, -122.000	2.25	Gas	11.91	7	Yolo
Princeton Gas	39.390, -122.020	11.0	Gas	9.97	13	Colusa
Wild Goose Gas	39.323, -121.890	75.0	Gas	6.53	21	Butte

1.4.7.4 Meteorological Data and Approach

As described in Section 1.2.7, we used meteorological data, UGS locations, and the NOAA real-time High-Resolution Rapid Refresh (HRRR) model to assess emissions dispersion.

With the HRRR data, we developed a wind rose dataset for each UGS site. For illustration, we provide in Figure 1.4-6 and Figure 1.4-7 the wind roses for the Aliso Canyon and McDonald Island facilities. These figures show the annual wind roses for each storage facility obtained from the HRRR model data for a one-year period at four different times of the day; 00-06 (night), 06-12 (morning), 12-18 (afternoon), 18-00 (evening) PST to understand the dominant or primary wind directions (and speed). For Aliso Canyon, the main wind directions are N-NNE, with high frequency of strong winds for most of the day. However, during the afternoon, winds come from SSW with considerably lower wind speeds. McDonald Island Gas presents winds persistently from W-NW through the day, with some rare events from S-E mostly during nights and mornings. Winds are generally weak with the exception of the afternoons, when the winds tend to be stronger.

More details on how we compared the results from different meteorological datasets, along with the presentation and evaluation of wind roses for each UGS site, are provided in Appendix 1.B.

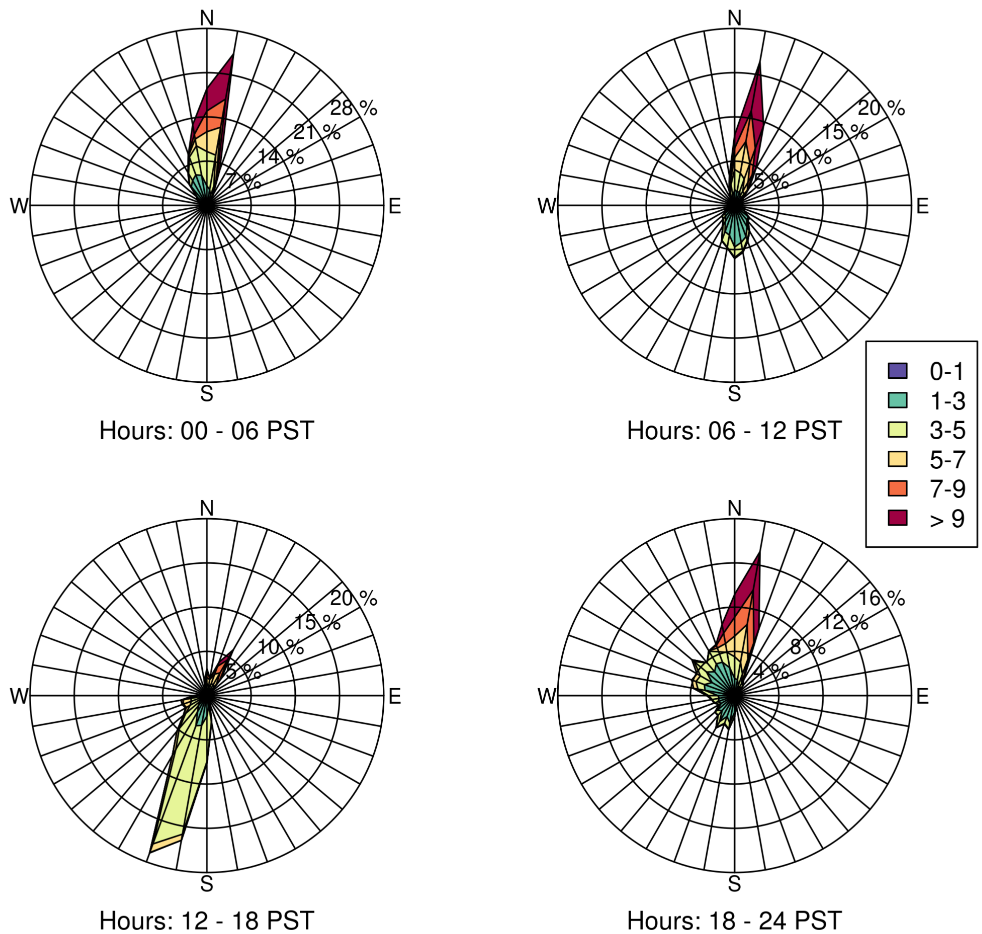


Figure 1.4-6. Wind roses at the Aliso Canyon UGS facility obtained from HRRR data.

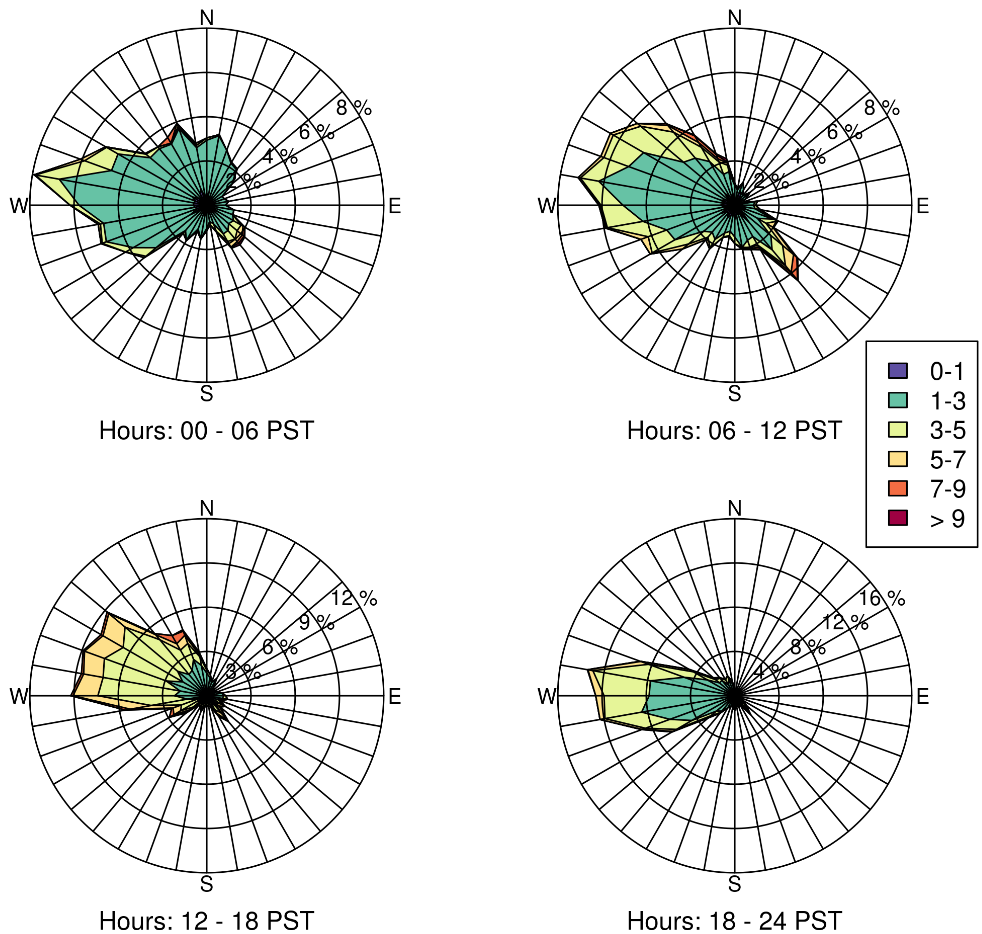


Figure 1.4-7. Wind roses at the McDonald Island UGS facility obtained from HRRR data.

1.4.7.5 Exposure Climatology

Figures 1.4-8–1.4-11 provide example contour plots for the annual mean tracer concentration/flux ratio (C/Q) (sometimes referred to as the "concentration over flux" ratio, even though Q is formally a flow rate) for Aliso Canyon, Gill Ranch, Honor Rancho, and Kirby Hill UGS facilities. Contour plots for all sites are provided in Appendix 1.B. The flooded contour plots show the spatial distribution of the C/Q ratio superimposed on a Google Earth image of the facility. The + symbols on the contour plots indicate the locations of the wells, the * symbol shows the centroid of the facility, and the black contours show the boundary of the storage facility. Red colors on the flooded contours indicate high values of C/Q ratio, while the blue colors indicate low values of C/Q ratio. This implies that for a given emission rate, the concentration field decays exponentially with distance from the storage facility.

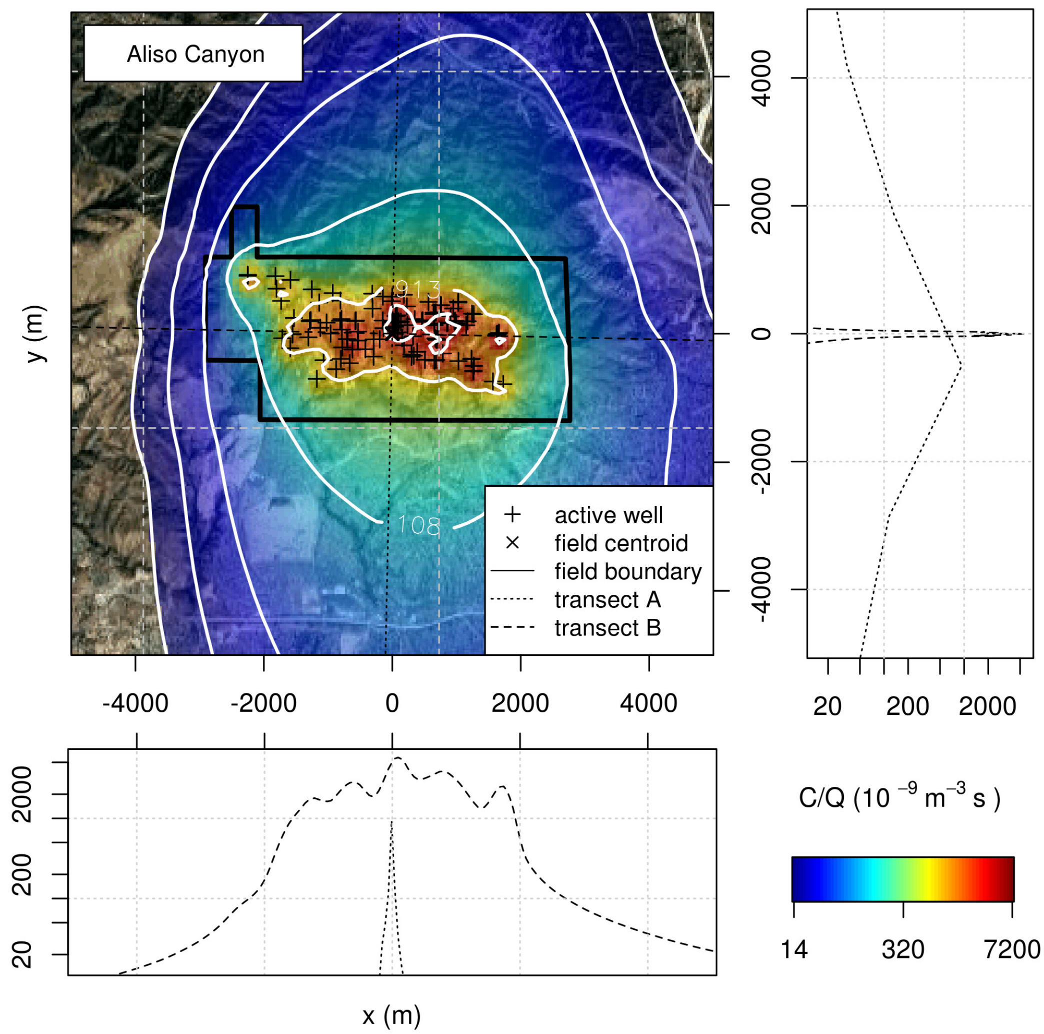


Figure 1.4-8. Annual mean tracer concentration/flux ratio (C/Q) for Aliso Canyon). Side panels are the concentration profiles along the transects marked on the map.

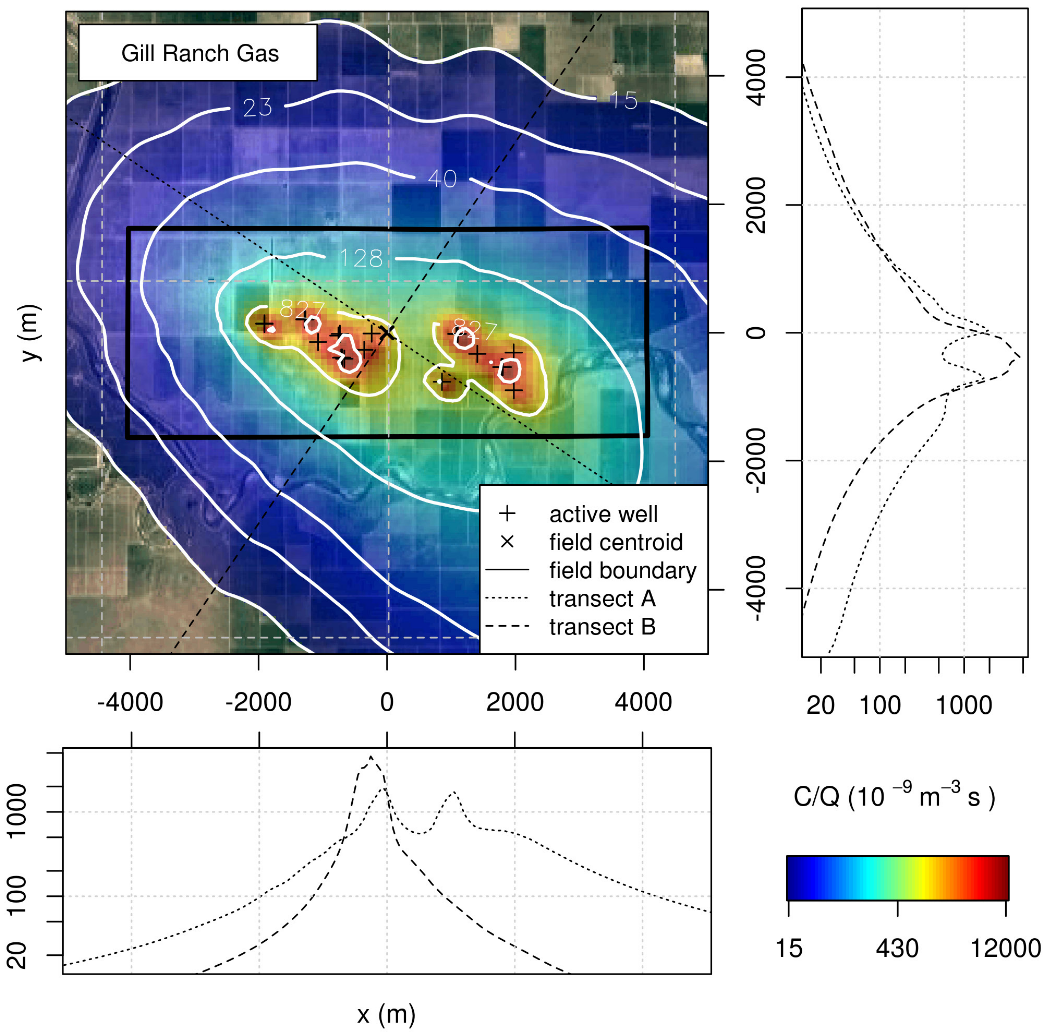


Figure 1.4-9. Annual mean tracer concentration/flux ratio (C/Q) for Gill Ranch. Side panels are the concentration profiles along the transects marked on the map.

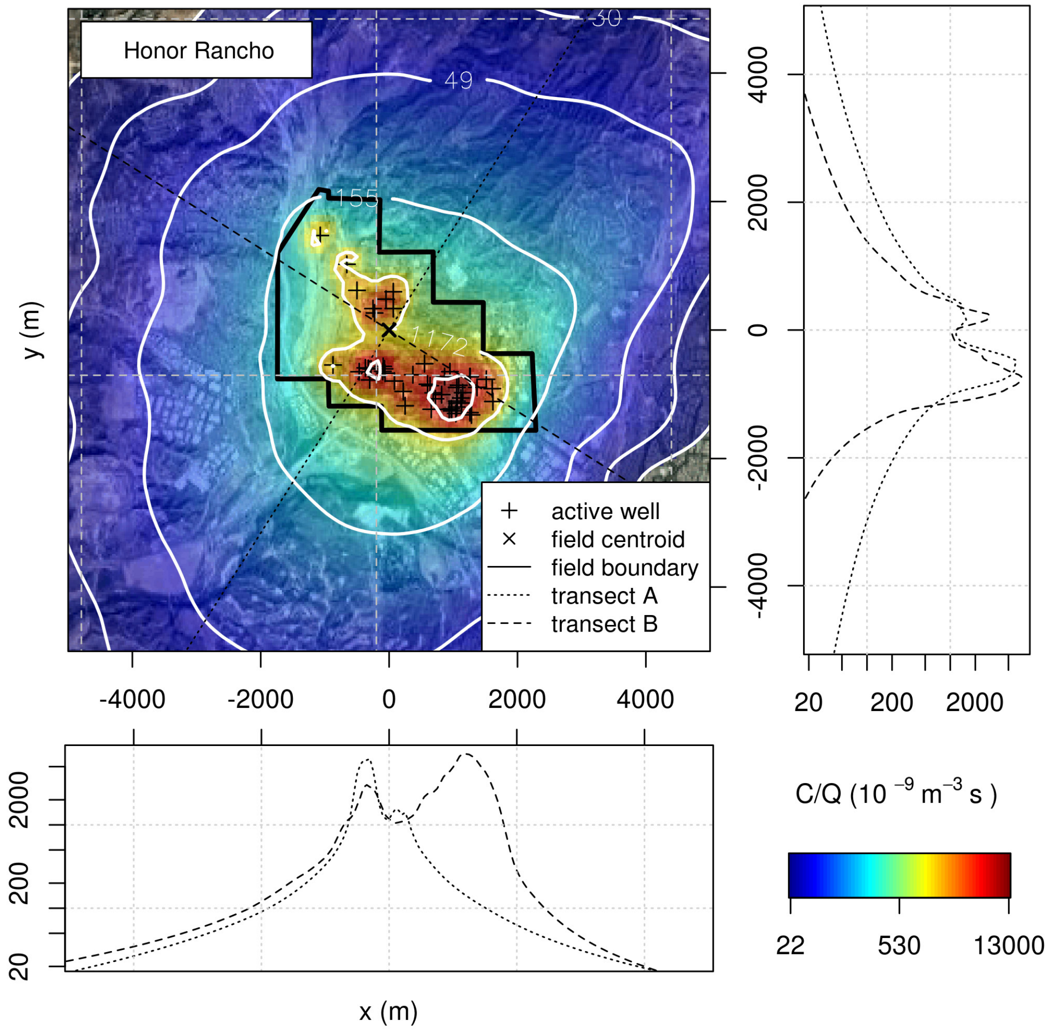


Figure 1.4-10. Annual mean tracer concentration/flux ratio (C/Q) for Honor Rancho. Side panels are the concentration profiles along the transects marked on the map.

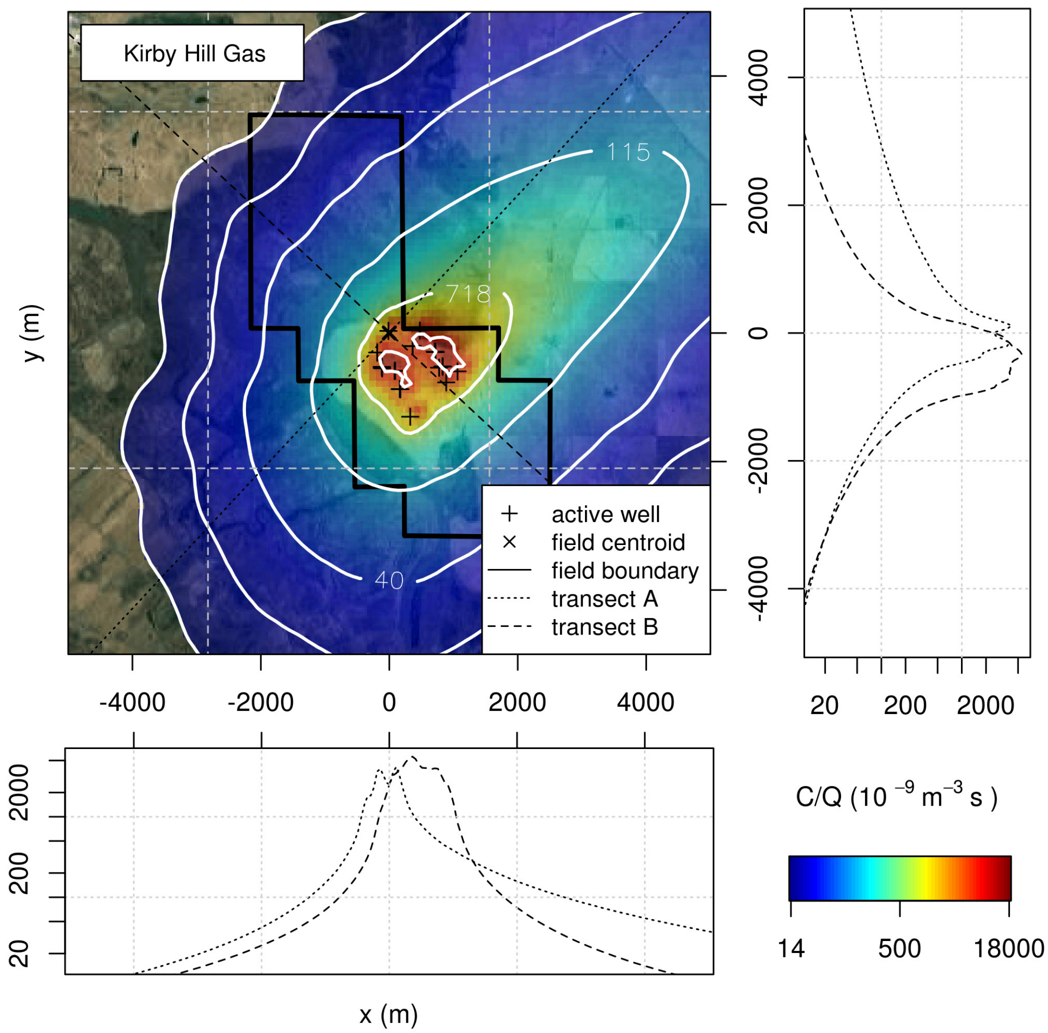


Figure 1.4-11. Annual mean tracer concentration/flux ratio (C/Q) for Kirby Hill. Side panels are the concentration profiles along the transects marked on the map.

The contour plots (Figures 1.4-8–1.4-11) also show white contour lines representing the 65%, 75%, 85%, 95%, 99%, and 99.9% quantile level. The quantile levels were computed from the cumulative distribution of all the pixel values in the computational domain. Each quantile level corresponds to a unique C/Q value for each storage facility. Figure 1.4-12 shows the C/Q ratio for each storage facility for each quantile level. For example, the 99% quantile level for Aliso Canyon corresponds to a C/Q value of ~ 1000 × 10^{-9} m^{-3} s (See Figure 1.4-12). A 99% quantile level for Aliso Canyon implies that 99% of all the C/Q values for that UGS facility were smaller than the C/Q value of 1000 × 10^{-9} m^{-3} s. Similarly, the 66% quantile level for Aliso Canyon implies that 66% of the C/Q values were smaller than 20 × 10^{-9} m^{-3} s.

The air dispersion modeling accounts for seasonal effects, boundary layer conditions, and temperature inversions through the boundary layer stability parameters. For example, the stability conditions could be very different during the day (sunny or cloudy day) than during the night. The dispersion model and the role of stability parameters are discussed in detail in Appendix 1.B.

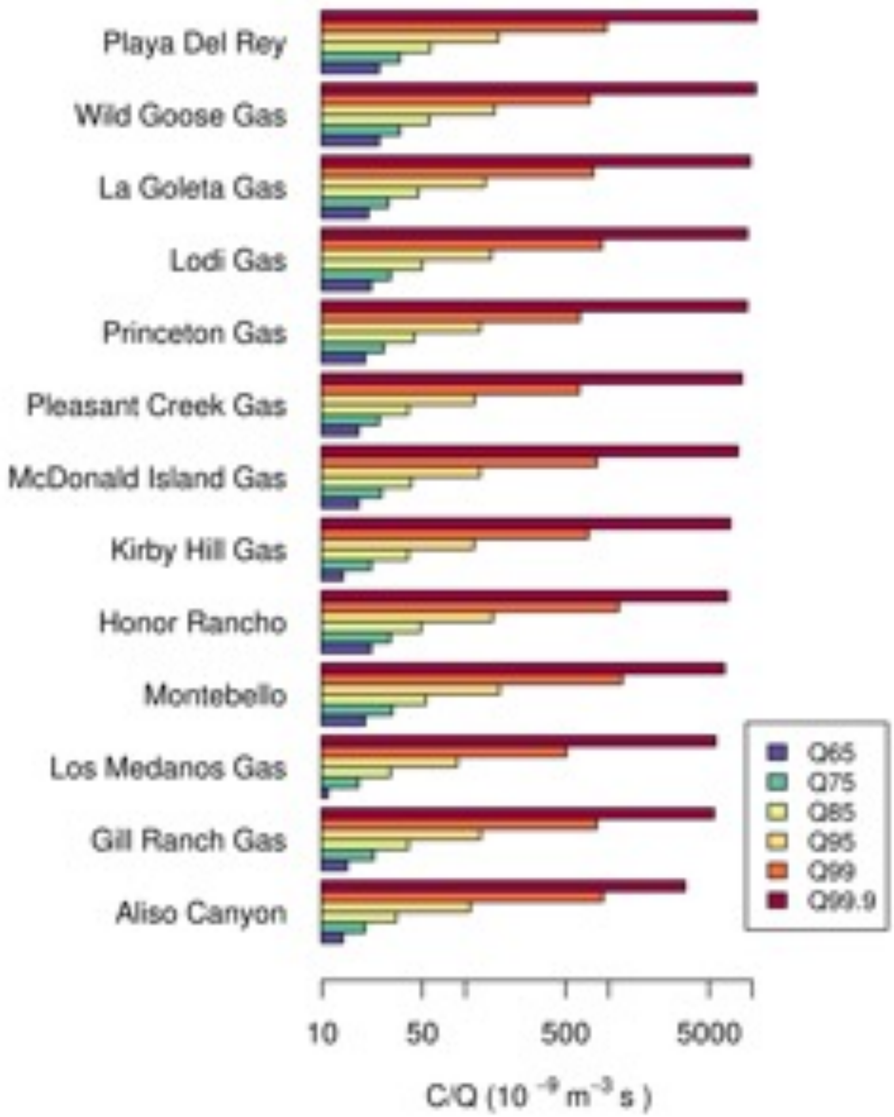


Figure 1.4-12. Percentiles calculated for the annual mean tracer concentration/flux ratio for each storage facility.

Different storage facilities will have different C/Q values corresponding to a certain quantile level. The 99% quantile level for Aliso Canyon has a C/Q value of 1000 × 10^{-9} m^{-3} s, while the 99% quantile level for Los Medanos is approximately 500 × 10^{-9} m^{-3} s. This is due to differences in meteorological conditions at the two facilities. It should be noted that the contour corresponding to the 99% quantile level for Aliso Canyon and Los Medanos roughly covers a similar area. Figure 1.4-12 also clearly shows the decaying values of the percentiles, indicating the distribution is very skewed.

The contour plots (Figures 1.4.10 & 1.4.11) also show the location of two perpendicular transects (dashed lines) crossing at the centroid of the field. The x-y plots to the bottom of the contour plot show the variability of the C/Q ratio (plotted on the Y axis) as a function of distance (measured along the X axis). Similarly, the x-y plots to the right of the contour plot shows the variability of the C/Q ratio (plotted on the X axis) as a function of the distance (measured along the Y axis).

P99.9 values ranged from 3,400 to 10,800 × 10^{-9} m^{-3} s, for Aliso Canyon and Playa del Rey, respectively (see Figure 1.4-12). A big drop in the values is noticeable by looking at the P99, which ranged from 508 to 1,240 × 10^{-9} m^{-3} s, for Los Medanos Gas and Montebello, respectively. P95 ranged from 88 to 173 × 10^{-9} m^{-3} s, coincidently for Los Medanos and Montebello, respectively. P85 was 30 to 57 × 10^{-9} m^{-3} s for Los Medanos and Playa del Rey, respectively, while P75 was 18 to 35 × 10^{-9} m^{-3} s, for Los Medanos and Wild Goose Gas. Last, P65 ranged from 11 to 25 × 10^{-9} m^{-3} s, for Los Medanos and Wild Goose Gas.

These values imply that the average C/Q ratio of fugitive but persistent emissions from underground storage facilities decays dramatically with the distance from the source. Overall, large values are only found in the first 0.5 km^2 surrounding the source, while in the first 5 km^2 the ratio gets reduced by 5–15 times and in the first 25 km^2 by 35-75 times.

Consistently, Los Medanos shows the smallest values for the percentiles, with the exception of P99.9, which is smallest for Aliso Canyon. The largest values for the percentiles are more equivocal between Playa del Rey, Montebello, and Wild Goose Gas.

Table 1.4-12 shows the annual mean C/Q ratio for the defined quantiles for each storage facility at four different times of the day; 12:00 a.m. to 6:00 a.m. (night), 6:00 a.m. to 12:00 p.m. (morning), 12:00pm to 6:00pm (afternoon), 6:00pm to 12:00am (evening) Pacific Standard Time (PST).

Larger C/Q ratios are always found during nights and evenings, as expected. This is due to the increased atmospheric stability and generally calmer winds during nights. Overall, night-afternoon differences are on the order of 2–12 times, depending on the contour level and facility, with a mean of 3.7 times. Playa del Rey exhibits the largest differences, while Los Medanos exhibits the smallest difference between night-afternoon hours.

Table 1.4-12. Annual mean tracer concentration/flux ratio ($m^{-3}s$) scaled by 10^9 for the quantiles (Q65, Q75,Q85, Q95, Q99, Q99.9) for each storage facility at four different times of the day; 00-06 (night), 06-12 (morning), 12-18 (afternoon), 18-00 (evening) PST.

Underground Storage Facilities	Hours (PST)	Q65	Q75	Q85	Q95	Q99	Q99.9
Playa del Rey	00-06	38	58	96	279	1580	18413
Playa del Rey	06-12	10	15	26	88	479	3642
Playa del Rey	12-18	3	6	18	68	374	3181
Playa del Rey	18-24	36	53	87	254	1425	17309
Montebello	00-06	36	53	88	279	2061	10625
Montebello	06-12	10	15	26	95	596	2158
Montebello	12-18	4	7	19	76	494	2349
Montebello	18-24	30	45	79	246	1827	10278
Aliso Canyon	00-06	11	21	42	136	1130	4589
Aliso Canyon	06-12	6	9	17	63	422	1216
Aliso Canyon	12-18	5	9	17	62	405	1314
Aliso Canyon	18-24	25	35	57	180	1689	6727
Honor Rancho	00-06	34	47	76	234	1826	11112
Honor Rancho	06-12	8	12	21	76	539	2285
Honor Rancho	12-18	5	9	18	61	349	1688
Honor Rancho	18-24	37	51	82	255	1882	12196
La Goleta Gas	00-06	33	45	71	203	1155	15748
La Goleta Gas	06-12	10	14	25	79	452	3211
La Goleta Gas	12-18	7	11	20	64	363	3708
La Goleta Gas	18-24	33	46	74	207	1132	16781
Gill Ranch Gas	00-06	23	35	59	182	1229	8779
Gill Ranch Gas	06-12	9	14	25	89	532	2397
Gill Ranch Gas	12-18	8	13	26	88	526	2861
Gill Ranch Gas	18-24	17	27	50	158	1038	7487
McDonald Island Gas	00-06	31	43	69	201	1382	14645
McDonald Island Gas	06-12	10	14	25	81	492	3400
McDonald Island Gas	12-18	9	12	21	66	406	3330
McDonald Island Gas	18-24	18	30	56	166	1075	9427
Lodi Gas	00-06	33	49	82	245	1440	16101
Lodi Gas	06-12	11	16	28	92	507	3368
Lodi Gas	12-18	9	14	23	75	422	3469
Lodi Gas	18-24	30	42	68	204	1223	14011
Los Medanos Gas	00-06	11	21	42	123	704	7545
Los Medanos Gas	06-12	7	11	18	59	331	2561
Los Medanos Gas	12-18	7	10	18	55	312	2747
Los Medanos Gas	18-24	14	25	43	123	716	8953
Wild Goose Gas	00-06	41	56	89	245	1144	15177
Wild Goose Gas	06-12	13	18	31	97	459	5288

Underground Storage Facilities	Hours (PST)	Q65	Q75	Q85	Q95	Q99	Q99.9
Wild Goose Gas	12-18	12	17	29	88	412	4685
Wild Goose Gas	18-24	36	49	78	213	994	13308
Princeton Gas	00-06	32	44	70	194	956	15574
Princeton Gas	06-12	10	14	25	78	396	4256
Princeton Gas	12-18	10	14	24	74	392	3964
Princeton Gas	18-24	27	37	59	165	804	13947
Kirby Hill Gas	00-06	20	32	60	172	1103	11336
Kirby Hill Gas	06-12	9	14	24	77	450	3157
Kirby Hill Gas	12-18	8	12	21	64	377	3134
Kirby Hill Gas	18-24	17	28	53	155	973	10236
Pleasant Creek Gas	00-06	28	38	61	173	945	14671
Pleasant Creek Gas	06-12	11	16	26	81	412	3519
Pleasant Creek Gas	12-18	9	13	22	68	358	3848
Pleasant Creek Gas	18-24	21	33	54	153	850	13136

1.4.7.6 Refined Proximal Population Assessment Using Air Dispersion Modeling

Above in this section, we estimated populations and sensitive receptors in proximity to UGS facilities using distance alone, given that at any time of routine or off-normal releases of gas to the atmosphere, the wind may not blow in the annual average direction. In Table 1.4-13, we provide the results of our assessment of population counts for each quantile level for each UGS facility. Analysis covers all the quantile levels discussed in the previous section and has also been extended to the 50% quantile level.

Table 1.4-13. Total population counts for each wind rose contour quantile level by UGS facility. Facilities are in descending order from high population to low population.

Underground Storage Facility	99.9 Quantile Level	99% Quantile Level	95% Quantile Level	85% Quantile Level	75% Quantile Level	65% Quantile Level	50% Quantile Level
Montebello	133	3,038	30,779	178,963	313,758	422,241	607,185
Playa del Rey	263	6,613	36,590	106,209	161,038	223,529	343,059
Aliso Canyon	0	38	6,910	37,027	88,854	144,290	219,991
La Goleta Gas	26	695	14,542	57,823	75,858	89,830	99,546
Honor Rancho	0	256	8,248	23,776	41,099	61,410	90,520
Los Medanos Gas	0	10	2,326	14,237	24,188	44,382	90,444
Lodi Gas	18	218	1,056	3,243	5,520	7,010	13,634
Pleasant Creek Gas	0	2	28	6,123	7,413	7,704	8,103
McDonald Island Gas	3	25	95	222	309	3,767	6,223
Princeton Gas	3	15	35	309	427	472	569
Gill Ranch Gas	0	0	4	60	168	279	492
Kirby Hill Gas	0	4	21	129	180	218	272
Wild Goose Gas	0	2	4	16	31	53	97

We also calculated population densities for each combination of quantile level (6 levels) and underground gas storage facility (13 facilities), providing 78 values. Similar to the Tier 1 results, we categorized each quantile level and underground gas storage facility combination as “None,” “Very low,” “Low,” “Medium,” and “High” population density. With the Tier 1 population counts, 55.9% of the buffer gas storage facility results are located in very low or no population density areas, while 28.7% are located in medium or high population density areas. In contrast, with the wind rose population counts, 47.4% of the quantile level gas storage facility results are located in very low or no population density areas, while 38.5% are located in medium or high population density areas. This demonstrates that when wind direction is considered, more densely populated areas will be affected than if radial buffers are considered alone. These results show the importance of incorporating wind direction data into an evaluation quantifying proximal populations that could potentially be at risk. For illustrative purposes, in Figures 1.4-13–1.4-15, we show the relationship between the location of Aliso Canyon, La Goleta, and Montebello UGS facilities, the air dispersion model results, and population density.

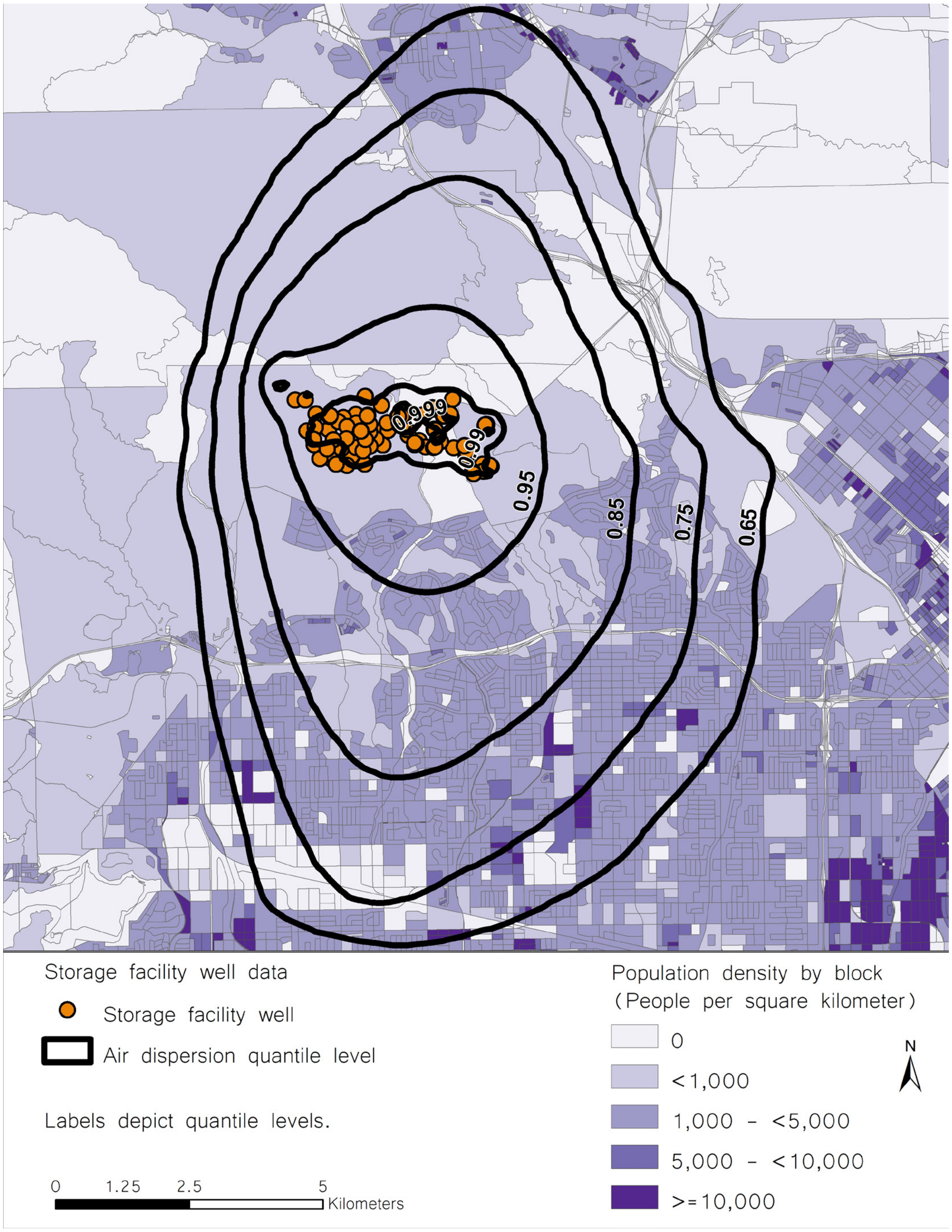


Figure 1.4-13. Air dispersion quantiles and population density at the Aliso Canyon UGS facility.

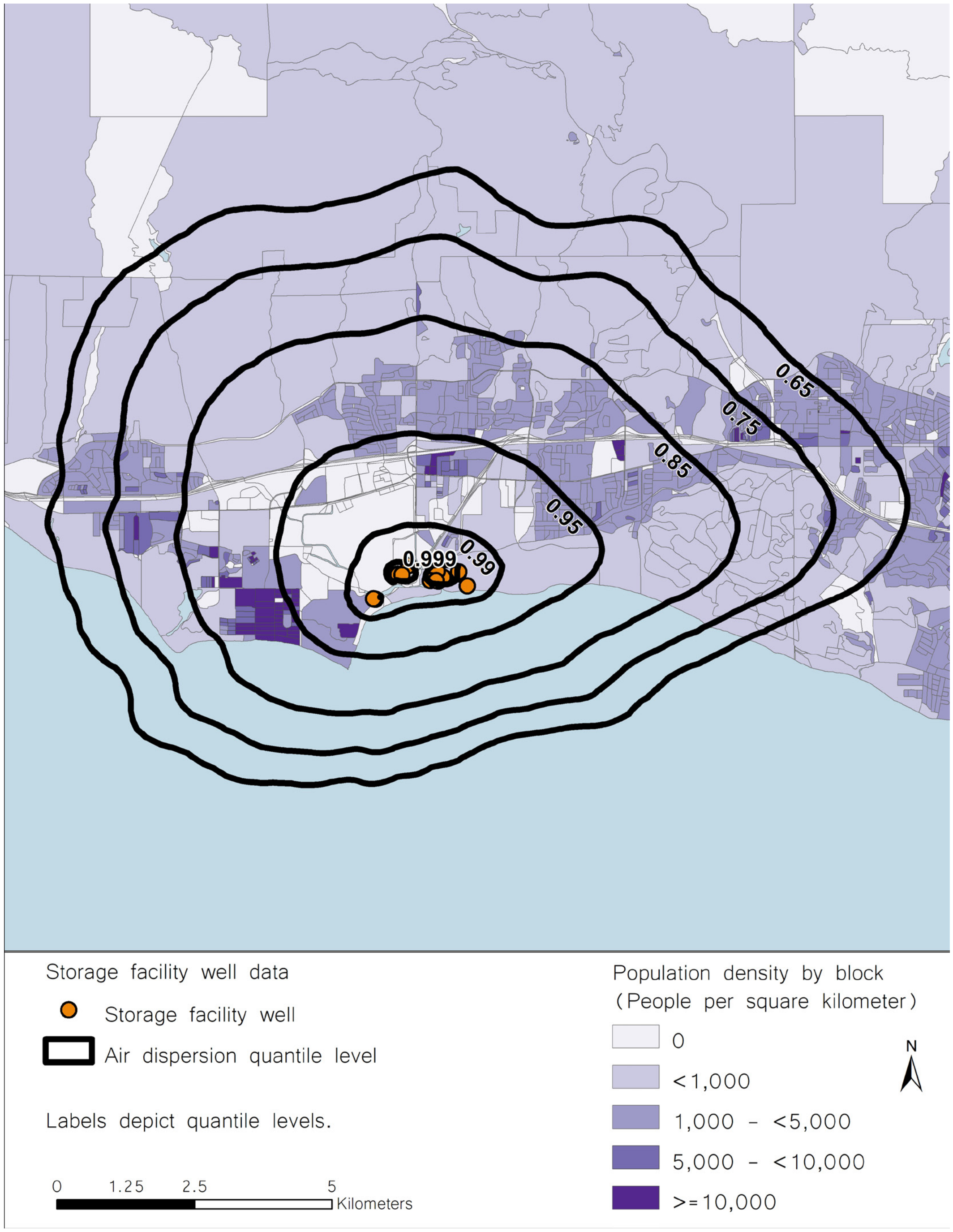


Figure 1.4-14. Air dispersion quantiles and population density at the La Goleta UGS facility.

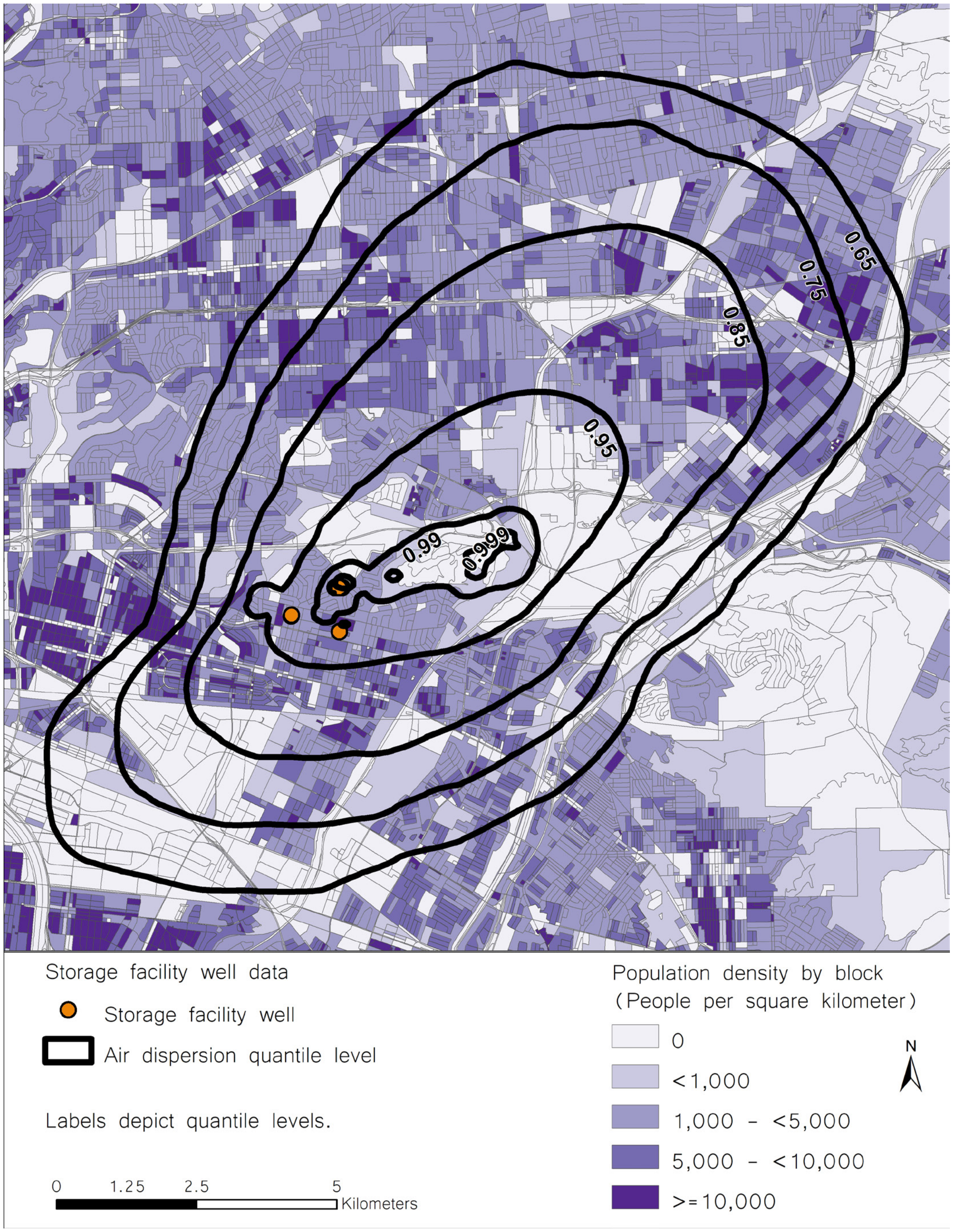


Figure 1.4-15. Air dispersion quantiles and population density at the Montebello UGS facility.

The wind dispersion modeling indicated that air pollutants emitted by UGS facilities could travel out to beyond 8,000 m (~5 miles) at the 0.50 quantile level, depending on the geographic location of each UGS facility, especially during a larger loss-of-containment event such as the one that occurred at Aliso Canyon. To incorporate this information, we created a final radial buffer that we call the QL50 buffer to indicate the maximum distance per storage facility from the outermost extent of the UGS well boundary to the 0.50 quantile level boundary. This distance varies between sites, ranging from 7,977 m at Lodi Gas to 12,037 m at Montebello, depending on and constrained by prevailing wind patterns, with a mean distance of 9,427 m.

Calculating population counts under the 0.50 quantile level distances is important, because available self-reported health symptoms data collected by LACDPH (2016c) during and after the 2015 Aliso Canyon incident extended out to similar distances. In fact, the majority of the reported symptoms potentially attributable to the 2015 Aliso Canyon incident were reported up to 16,090 meters (10 miles) from the facility (see Section 1.4.10). Consideration of distances greater than 10,000 m from a UGS facility, according to our air dispersion model, seemed not to be justified, because the C/Q values of UGS facilities began to level off around the 50th percentile.

The results of our QL50 population and sensitive receptor count assessment can be found in Table 1.4-14 below. We estimate that in total, 3,127,434 Californians live within the QL50 buffer area. Of these, 204,772 are under the age of five and 165,313 are age 75 or older. There are also substantial sensitive receptors within this area: there are 967 schools (966 open and 1 pending), 2,121 daycares (2,094 open and 27 pending), 519 residential elderly care facilities (470 open and 1 pending), and 46 hospitals.

Even with the variance in buffer distance, the facilities rank very similarly to the 8,000 m radial buffer with population count magnitudes. Montebello continues to have the highest population, with over 1.5 million people living within the QL50 area, while Wild Goose Gas has the lowest population, with a minimal 195 people. Six facilities have greater than 100,000 people within this area, and two facilities have greater than 500,000 people.

Table 1.4-14. Population and sensitive receptor counts for the QL50 buffer, by underground storage site; N/A = data not available.

Underground Storage Facility	Buffer Distance	Number of Residents	Under 5	Age 75 and Older	Number of Open Schools	Number of Children Enrolled in School	Number of Open Daycare Facilities	Number of Open Elderly Care Facilities	Number of Hospitals
Aliso Canyon	9,116 m	325,330	18,711	19,269	102	60,241	244	130	4
Gill Ranch	9,124 m	909	82	29	0	0	0	0	0
Honor Rancho	8,998 m	180,359	11,139	5,807	54	38,631	121	61	1
Kirby Hill	9,813 m	401	17	18	0	0	0	0	0
La Goleta	8,608 m	101,371	4,040	7,611	32	13,991	77	41	3
Lodi Gas	7,977 m	23,771	1,600	1,576	9	2,851	10	2	0
Los Medanos	9,743 m	223,069	15,640	10,407	63	29,169	176	92	3
McDonald Island	9,282 m	6,473	388	244	0	0	2	0	0
Montebello	12,037 m	1,594,128	113,206	81,789	482	273,453	877	59	26
Playa del Rey	9,506 m	691,757	39,352	38,121	218	93,325	577	85	9
Pleasant Creek	9,553 m	8,821	545	373	4	0	9	0	0
Princeton	9,686 m	848	41	59	2	169	0	0	0
Wild Goose	9,102 m	195	9	11	0	0	0	0	0

1.4.8 Explosion and Fire Hazards of Loss-of-containment Events

The accidental release of natural gas stored under high pressure at a UGS facility can pose a significant threat to people and property in the vicinity of the failure location. Based on the history of explosions and fires in the natural gas industry (e.g., from pipelines), it is important to consider these risks involving large volumes of gas, such as those stored in UGS facilities (CPUC, 2010). Among the significant hazards associated with such a release is thermal radiation from sustained fire and collapse of buildings from an explosion inside or in a partially confined area enclosed by buildings. Decompression cooling can cause small pipeline leaks to turn into large leaks.

The area of hazard associated with the damage will depend on the mode of failure, time to ignition, environmental conditions at the failure point, and meteorological variables. For example, ignited releases can produce pool fires, jet flames, vapor cloud fires, or fireballs, all of which behave differently and exhibit markedly different radiation characteristics. The thermal radiation hazards from hydrocarbon pool fires depend on a number of parameters, including the composition of the hydrocarbon, the size and shape of the pool, the duration of the fire, its proximity to the object at risk, and the thermal characteristics of the object exposed to the fire (Smith et al., 2011; Jo and Ahn, 2002).

Accidental release of hydrocarbon vapors or intentional disposal of unwanted gas can result in large turbulent diffusion flames and flares (Dryer et al., 2007; Montiel et al., 1996; Sklavaounos, 2006). Thermal radiation from flares and turbulent flames can represent substantial hazard to personnel, equipment, and the environment. The base diameter of a flare stack, height of the stack, and composition of the burning substance are important variables in determining the radiation from turbulent jet flames. Horizontal jet dispersion models that characterize the concentration profile and fire models that characterize the radiative heat flux can estimate the ground area (hazard zone) affected by credible failure scenarios. Leak rates and meteorological data can be combined with flammability/explosion-limit estimates to delineate the extent of the hazard zone (Benjamin et al., 2016; SFPE, 2008).

For many UGS facilities, the size of fire and explosion hazard zones can be larger than the infrastructure footprint, especially for facilities with gas processing and compressor equipment. The impacts of loss-of-containment (LOC) failure to UGS infrastructure are potentially very large (SFPE, 2008). Hazard zones should be delineated for each UGS facility to focus risk mitigation on elimination of leakage and ignition sources (loss prevention) and safer site-use planning. In this section, a method to estimate the size of the hazard zone based on atmospheric dispersion of the leaked gas is described.

As is the case for air dispersion modeling described above and in Section 1.2, meteorological data were collected from stations that are part of NOAA's Integrated Surface Database (ISD) and located closest to the various underground storage facilities. The High-Resolution Rapid Refresh (HRRR) also provided annual averaged values of meteorological data for each storage facility for four different times of the day; 00-06 (night), 06-12 (morning), 12-18 (afternoon), 18-24 (evening) PST. The averaged wind speed and wind direction data were subsequently combined with plume dispersion models to compute the methane concentrations downwind of the storage facility. Furthermore, since the leak rate (referred to frequently as the flux) from the storage facility is not known, a unit flow rate was assumed. Appendix 1.B provides detailed contour plots that show the average downwind concentration per unit flux for each storage facility.

The downwind concentrations per unit flow rate are particularly useful, since the contour levels can be multiplied by the actual leak rate to obtain the average concentrations downwind of the UGS facility. If the leak rates are very large, then downwind concentrations can be large as well; the concentrations in the model decay with distance from the leak in an exponential manner. When the leak rates are small, the downwind concentrations close to the leak site will be relatively small.

Under high leak rates, the downwind concentrations can be larger than the flammability or explosions limits. Flammability limits refer to the range of compositions, for fixed temperature and pressure, within which exothermic chemical reactions are possible. Flammability limits are given in terms of fuel concentration (by volume) at a specified pressure and volume. The lower flammability limit for pure methane is 4.4% (percent volume of air), while the upper flammability limit is 16.4%. For comparison, the lower and upper flammability limits of pure ethane are 3% and 12.4%, respectively.

If the leak rates are very high, then the downwind concentrations can be larger than the lower flammability limits. Results of the detailed air dispersion calculations provided in Appendix 1.B show that the C/Q contours extend well beyond the boundary of the storage facility. This implies that the size of the hazard zone can be much larger than the infrastructure footprint and the LOC hazard can be potentially very large.

This analysis points to the need for clearly establishing the extent of the hazard zone around each of the 13 UGS facilities in California. Establishing the extent of the hazard zone would focus the mitigation efforts on eliminating leakage and ignition sources as well as safer site-use planning.

1.4.8.1 Minimum Flux Required to Reach Flammability Limits

In this section, we present the minimum leak rate required to reach the lower flammability limit in the vicinity of each storage facility. The minimum methane volume fraction required in a gas mixture to reach flammability is 0.044; this limit is referred to as the lower flammability limit (LFL) (SFPE, 2008). The approach used to compute the flammability limits (discussed in this section) is fundamentally different from that used to understand health effects (described earlier in this section). In case of health effects, the average values (long-term effects) were presented. On the other hand, in this section we are interested in the worst-case scenario for flammability and explosion limits.

To estimate the flammability risk under possible catastrophic leak events of an underground storage facility, it was assumed that any single well could leak at any time through the year. It is also assumed that the leak rate is constant in time. More complex computational fluid dynamics (CFD) tools can account for leak rates that vary with time. For a storage facility, the plume concentrations were computed hourly for each active well independently (concentration fields do not add up) during the period of interest. For this analysis, the hourly meteorological fields were assumed for a one-year period, as described in earlier sections. Subsequently, the maximum concentration through the year generated by any of the plumes was selected as the peak concentration for each point (pixel) of the computation domain. This approach enables us to compute the maximum possible hourly concentration for any known flux at any point in the domain of interest downwind of the storage facility. We next computed the minimum leak rate required to reach the lower flammability limit for methane at each point in the computational domain. The analysis and results presented in this section do not account for the vertical momentum-dominated jet that will occur during a high-pressure blowout scenario, nor does the analysis account for the thermal effects of a burning cloud or fire ball. These effects can be approximated to some extent through the concept of stack height. Multiphase flows involving a mixture of oil and gas and orientation of the leak can also influence the results presented in this section.

Figures 1.4-16 through 1.4-20 show the contours for minimum leak rate required to reach a flammable Leak Rate for Flammability (LRF) mixture for each storage facility. The top panel of Figure 1.4-16 shows the results for the Aliso Canyon natural gas storage facility. The contour plot shows the spatial distribution of the minimum estimated leak rate to reach a flammable mixture superimposed on a Google Earth image of the facility. The + symbols on the contour plot indicate the location of the wells, the * symbol shows the centroid of the facility, and the black contour shows the boundary of the storage facility. Blue color on the flooded contour plot indicates that the flammability limit was reached for higher values of leak rate, while red color indicates that the flammability was reached for lower values of leak rates. Due to the exponential decay in the concentration field, lower values of leak rate to achieve flammability were found closer to the wells, while higher values were found away from the wells.

The contour plot also shows white contour lines representing the 15%, 5%, 1%, and 0.1% quantile levels. Each quantile level corresponds to a unique leak rate for each storage facility. The minimum leak rate required for flammability corresponding to the various quantile levels is shown in Table 1.4-15. The quantile levels were computed from the cumulative distribution of all the pixel values of leak rate in the computational domain. For example, the 15% quantile level for Aliso Canyon corresponds to a leak rate of 9,141 t/hour, while the 15% quantile level for Los Medanos corresponds to a leak rate of 13,251 t/hr. A 15% quantile level would imply that 15% of the values are inside the contour level. This implies that for Aliso Canyon, 15% of the values of leak rate to reach flammability were less than 9,141 t/hour. The 15% quantile level is the outermost level (farthest away from the storage facility/wells), while the 0.1% quantile is located closest to the wells. Leak rates corresponding to the 15% quantile levels are quite large as expected, and the rate gets smaller for smaller quantile levels.

Each contour plot also shows the location of two perpendicular transects (dashed lines) crossing at the centroid of the field. The x-y plots to the bottom of the contour plot show the variability of the minimum leak rate required to reach flammability (plotted on the Y axis) as a function of distance (measured along the X axis). Similarly, the x-y plots to the right of the contour plot show the variability of the minimum leak rate required to reach flammability (plotted on the X axis) as a function of distance (measured along the Y axis).

In addition, a reference contour (red) representing a leak rate of 50 tonnes/hr was added on the contour plot. This leak rate of 50 tonnes/hour was the peak leak rate measured at Aliso Canyon during the November 2015 period (Conley et al., 2016). The red contour shows the maximum possible extent of the flammable zone or hazard zone if a leak comparable to the Aliso Canyon leak occurred at any of the facilities.

Overall, the estimated leak rate to reach flammability increases significantly as we move away from the wells. This is due to the dispersion of the leaked gas, where the concentration decays exponentially with distance from the leak source. The 50 tonnes/hour contour (red) for Aliso Canyon in Figure 1.4-16 (top left panel) was contained within the boundary of the facility. If the leak rate at the Aliso Canyon facility was significantly larger, then the region outside the facility would also fall into the hazard zone. The required leak rate to expose the outside of the fields to flammability risk increases to approximately 2,300 tonnes/hour.

Results for Gill Ranch Gas (Figure 1.4-16, top right panel) shows that the 50 t/hr contour (red) is not continuous as for Aliso Canyon, but exhibits hazard regions around each well. Similar features are observed at Honor Rancho and Kirby Hill (Figure 1.4-16). This analysis indicates that facilities where the well pads are located at the boundary of the facility (as for Honor Rancho, Kirby Hill, La Goleta, Los Medanos, and Playa del Rey) would result in potential hazard zones that extend outside the facility. The analysis also indicates that the flammable zone (hazard zone) can extend beyond the facility for very large leak cases (much larger than that for the Aliso Canyon Incident).

Wild Goose (Figure 1.4-20) is a very interesting case, because it shows a circular pattern around the source. This is the case of a point source. The circular pattern results from the fact that, through the year, there is at least one hour of meteorological conditions yielding to the largest values for every direction. This result allows us to say that for point sources, a worst-case scenario estimation may very well be drawn with a simpler one-dimensional plume model.

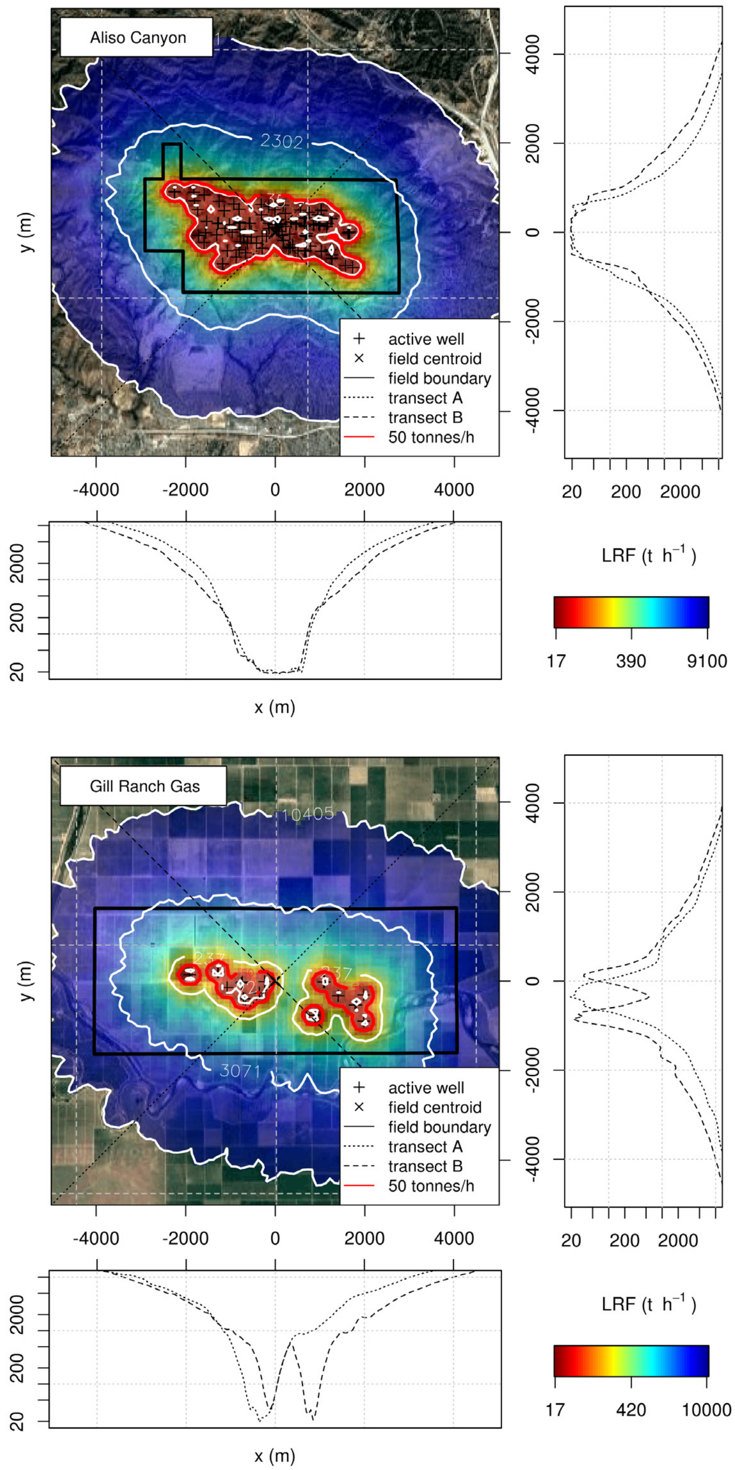


Figure 1.4-16. Contours of minimum leak rate required to reach lower flammability limit (LRF) for Aliso Canyon (top) and Gill Ranch (bottom) underground gas storage facilities.

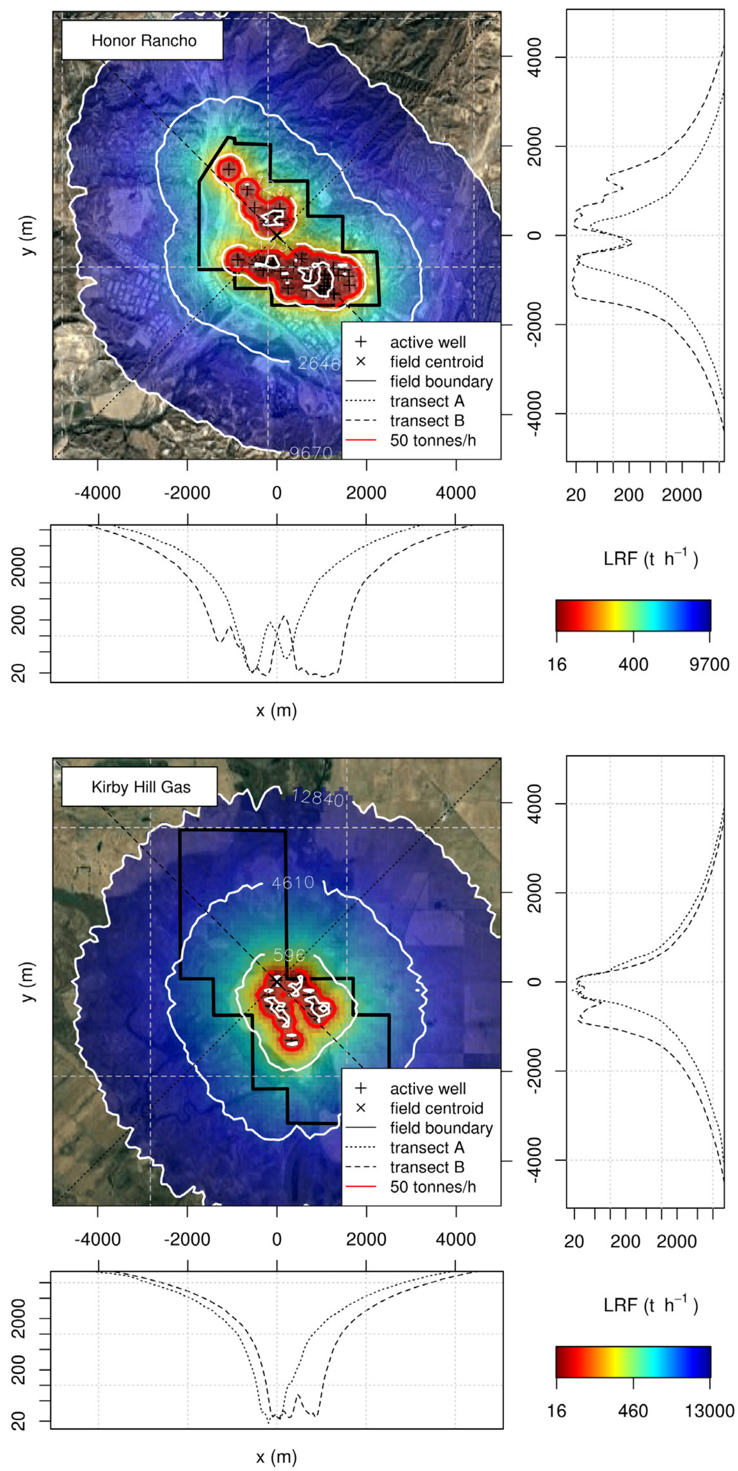


Figure 1.4-17. Contours of minimum leak rate required to reach lower flammability limit (LRF) for Honor Rancho (top) and Kirby Hill (bottom) underground gas storage facilities.

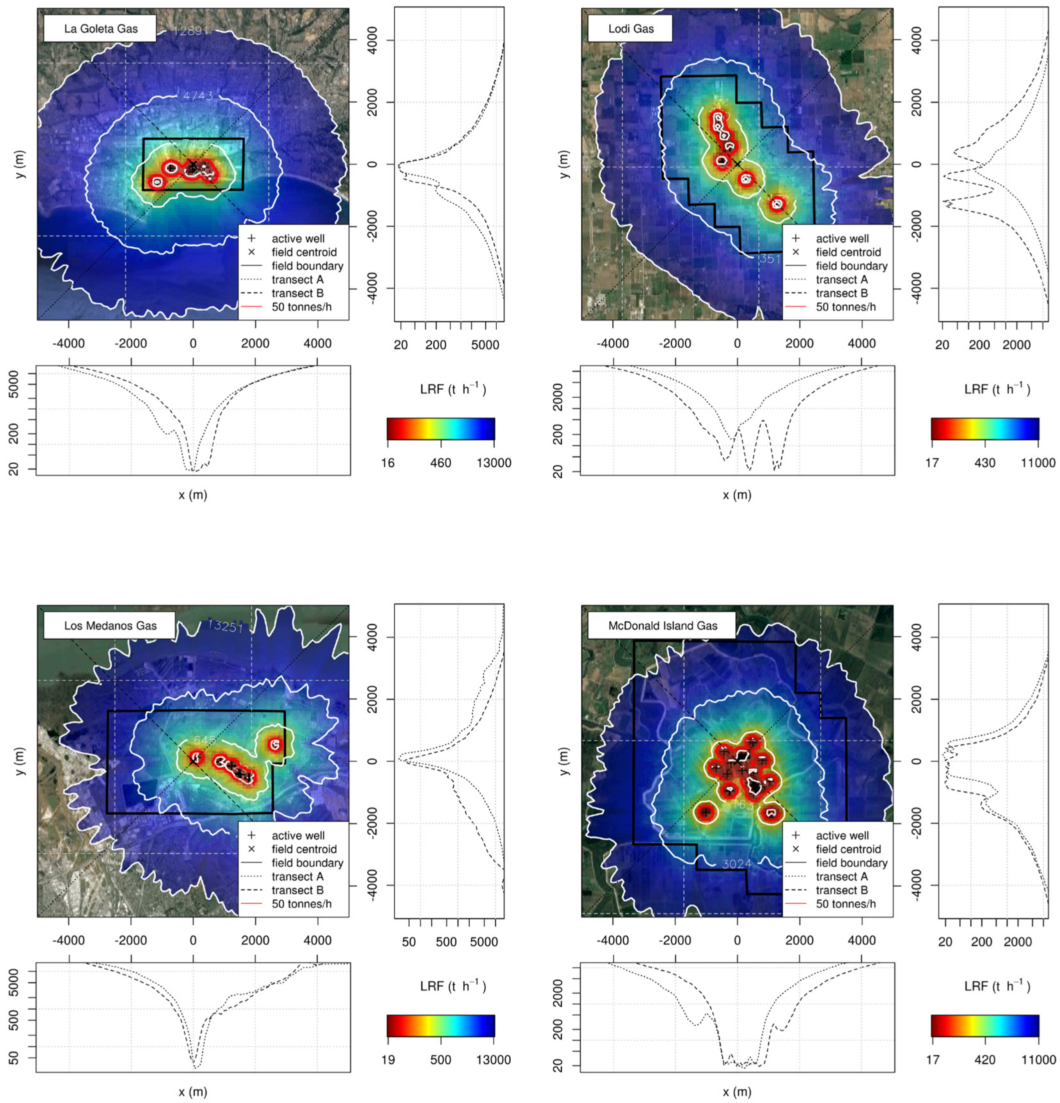


Figure 1.4-18. Contours of minimum leak rate required to reach lower flammability limit (LRF) for La Goleta Gas, Lodi Gas, Los Medanos Gas, and McDonald Island underground gas storage facilities.

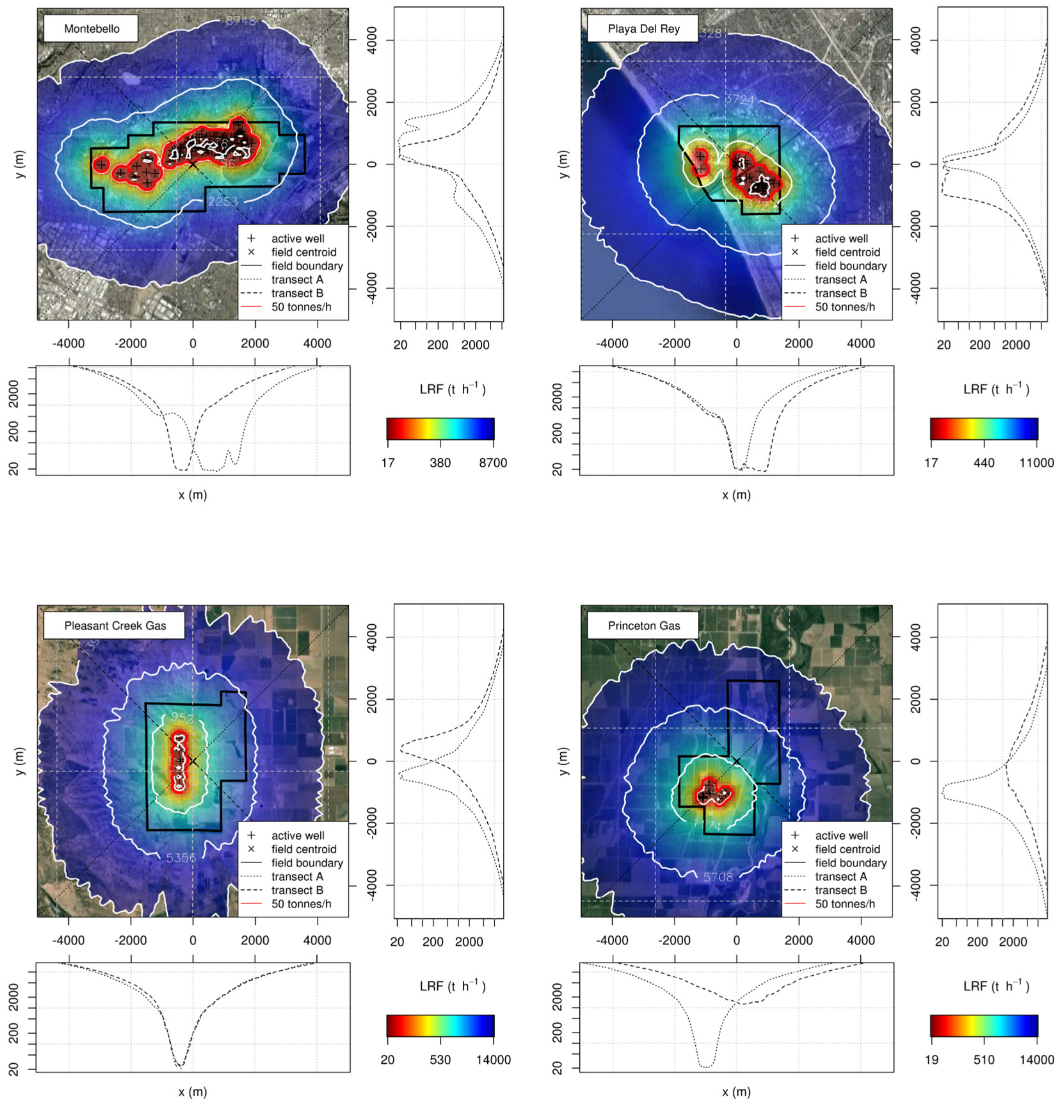


Figure 1.4-19. Contours of minimum leak rate required to reach lower flammability limit (LRF) for Montebello, Playa del Rey, Pleasant Creek, and Princeton underground gas storage facilities.

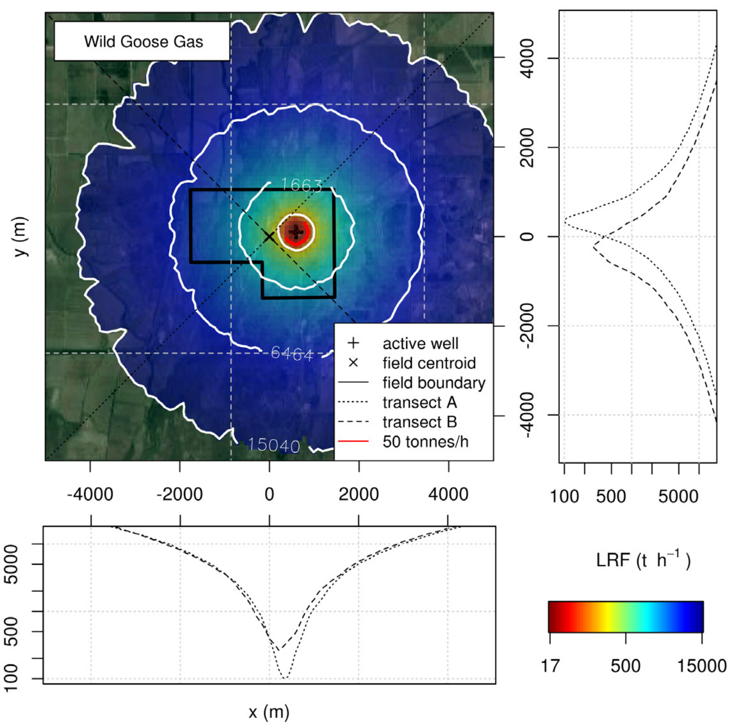


Figure 1.4-20. Contours of minimum leak rate required to reach lower flammability limit (LRF) for Wild Goose underground gas storage facilities.

Table 1.4-15. Estimated minimum leak rate (t / hour) for flammability corresponding to the 15%, 5%, 1%, and 0.1% quantile levels.

Storage Facility	**q15**	**q05**	**q01**	**q00.1**
Playa del Rey	11328	3724	372	19
Montebello	8748	2253	66	18
Aliso Canyon	9141	2302	35	18
La Goleta Gas	12891	4743	743	22
Gill Ranch Gas	10405	3071	237	22
Honor Rancho	9670	2646	123	18
McDonald Island Gas	10619	3024	163	20
Lodi Gas	10998	3519	430	23
Los Medanos Gas	13251	4549	645	29
Wild Goose Gas	15040	6464	1663	143
Princeton Gas	14160	5708	1174	35
Kirby Hill Gas	12840	4610	596	21
Pleasant Creek Gas	13960	5356	952	27

1.4.9 Public Health Hazards Arising from Potential UGS Impacts on Underground Sources of Drinking Water (USDW)

As discussed in Section 1.2, there are historical cases of stray gas migration in the subsurface from a loss of zonal isolation of gas into Underground Sources of Drinking Water (USDW) in California. Contamination of USDW with methane and other associated compounds introduces routes of exposure via drinking water, bathing, and other human water uses. To date, there are limited available data to assess the risk of USDW contamination from stray gas and other fluid migration from UGS facilities; however, such events can expose populations that rely on these aquifers for domestic consumption to a variety of chemical constituents. Monitoring should be carried out to detect and prevent or mitigate gas and other fluid migration from UGS storage facilities (surface and subsurface) into USDW.

The only publicly available assessment of impacts to water resources to date following the SS-25 well LOC event at the Aliso Canyon UGS Facility was sampling of *surface* water, conducted by Geosyntec Consultants (Geotracker, 2017). Geosyntec Consultants was contracted by SoCalGas in response to a 13267 order by the California State Water Resources Control Board following the SS-25 event (Geotracker, 2017). This assessment focused only on contamination of surface water with respect to deposited “work-over fluids” used in the SS-25 well kill attempts and did not find evidence of contamination (Geosyntec, 2017). However, aside from the highly narrow chemical scope of the study which fails to account for many of the known substances that would be appropriate to test for – as previously discussed in this chapter – this approach suffers from other shortcomings including that sampling did not take place until after a number of precipitation events. This delay introduces significant uncertainty given that chemicals that may have been deposited could have either eroded or been washed away prior to sampling. It is also worth stating, again, that it is more likely that groundwater would be impacted from such an event compared with surface water. Geosyntec Consultants is to perform a subsurface water study near SS-25 (Geotracker, 2017), but to date this report has not been released and there are questions as to whether data collection has yet commenced.

1.4.10 Large UGS Loss-of-containment Events and Public Health: The Case of the 2015 Aliso Canyon Incident

As noted in Sections 1.2 and 1.5 of this report, the blowout of the SS-25 well at the Aliso Canyon UGS Facility (Aliso Canyon) resulted in the largest atmospheric emission of methane from a single source in UGS history in the United States (Conley et al., 2016). The 2015 Aliso Canyon incident side bar in Section 1.2 describes what is known so far about the SS-25 well and the challenges to bring this loss-of-containment (LOC) event under control. The incident resulted in thousands of households being temporarily relocated and impacted the health of tens of thousands of people. While this report as a whole concerns underground gas storage facilities in California in general, the 2015 Aliso Canyon incident provides an important case study to assess the human health hazards, risks, and impacts of a large UGS disaster. The Aliso Canyon case is also important to assess from a public health perspective, given that it is the only UGS facility to be subjected to substantial air and environmental quality monitoring.

While the mass of methane emitted from the SS-25 blowout is well characterized (Conley et al., 2016; CARB 2016a), the mass of toxic air pollutant emissions and their resultant atmospheric concentrations and exposures to human populations are more uncertain.

As is the case for any large-scale emission—UGS or otherwise—in order to understand the environmental public health hazards, risks, and impacts - data must be available for a variety of factors, including but not limited to:

1. The composition of the substances emitted to the atmosphere

2. The rate and magnitude of emissions

3. The acute and chronic toxicity of the emitted substances

4. The extent of exposure to human populations.

Our team made formal attempts to gain access to data on the chemical composition of gas that is stored in UGS facilities, including gas stored at the Aliso Canyon UGS facility. The documentation and summary of these unsuccessful efforts are detailed in Appendix 1.D. The lack of motivation and effort on the part of operators to provide detailed chemical composition analyses may arise because operators take measurements to meet the tariffed standards for pipeline quality. These types of measurements are not sufficient for us to conduct a full assessment of air pollutant emissions and associated health effects. There may also be other reasons that operators failed to share these data with our study team.

What was shared with us was often the percentage breakdown of typical constituents of natural gas, with limits of reporting often at 1% or more. However, 1% of a substance in natural gas is 10,000 parts per million (ppm) or 10 parts per thousand (ppt). Even with substantial dilution of gases in the atmosphere, some harmful substances pose risks at ppt or parts per billion (ppb) levels in gas. CalEPA Reference Exposure Levels (RELs) are pollutant concentrations at or below which adverse health effects are not likely to occur (U.S. EPA, 2015). For instance, given that the REL for an 8-hour exposure to benzene is 3 ug/m^3 or 1 ppb, ppt levels in stored gas would easily reach this level in the diluting atmosphere. While it is not likely that 1% of gas withdrawn from the Aliso Canyon UGS facility is an air toxic such as benzene, this does suggest that it is critical to have access to these data to be able to estimate exposure of facility workers and nearby populations.

Based on the limits of on-site and nearby air dilution, we have determined that reporting values should be at least as low as one tenth of the relevant exposure reference values. The practice of making measurements for tariff standards needs to be modified to support health impact assessments. Lack of trace chemical detection precision may not matter at a

measuring and metering station out along the transmission pipeline. However, it can matter at UGS sites, because a UGS site concentrates more gas in one place, allowing for higher potential
leak quantities—suggesting the need for more precise composition measurement standards.

Given that we were not able to obtain the chemical composition of gas stored in Aliso Canyon at the level of detail needed, we are unable to determine the rate and magnitude of emissions of air pollutants that were emitted during the SS-25 and other events at the Aliso Canyon facility. Further, as mentioned earlier in this Section 1.4.5 and 1.4.6, the lack of spatial, temporal, and infrastructure-source specificity in reporting of toxic and criteria air pollutant releases renders it difficult to effectively estimate these health-damaging air-pollutant emissions during the SS-25 event.

With respect to the acute and chronic toxicity of the pollutants emitted from Aliso Canyon in general, the reported emissions inventories are generally helpful. For a full description of the substances reported as being emitted from Aliso Canyon, please see Section 1.4.5, where we analyze the emissions inventories.

There are three primary ways to assess the ambient concentrations of and potential exposures to toxic air pollutants enhanced by emissions from the 2015 Aliso Canyon incident, and the associated exposure of human populations both at the facility (occupational exposures) and in the Porter Ranch and other communities (community exposures). The best, but most difficult, approach is to conduct personal sampling on workers and community members. The second approach is to conduct *in situ* air quality monitoring during the event to empirically observe the changes in air quality over time. The third approach is to model atmospheric transport of the substances being emitted—that is, their emission rate and their dispersion patterns, based upon meteorological variables (e.g., Gaussian plume modeling) to determine concentrations and estimate exposures and associated risk to human health across geographic space and demographic groups.

As discussed previously, there is substantial uncertainty inherent in any approach that relies upon modeling of emissions data without access to data on the composition of stored gas. However, during the course of the SS-25 blowout at Aliso Canyon, there was a large amount of *in situ* air quality monitoring data collected. Despite the significant shortcomings of these monitoring networks – which are discussed below - these datasets help to elucidate concentrations of the health-damaging air pollutants monitored over time, and to a certain extent, across geographic space. Below, we provide a summary of key events during the SS-25 blowout and then describe the air quality monitoring efforts undertaken during the SS-25 well blowout and in the time after the blowout was successfully stopped.

1.4.10.1 Summary of Key Events During the Aliso Canyon SS-25 Well Blowout

Below, in Figure 1.4-21, we summarize many of the key events from the commencement of the SS-25 blowout to the successful killing of the well. This figure provides a chronological guide for reading this case study.

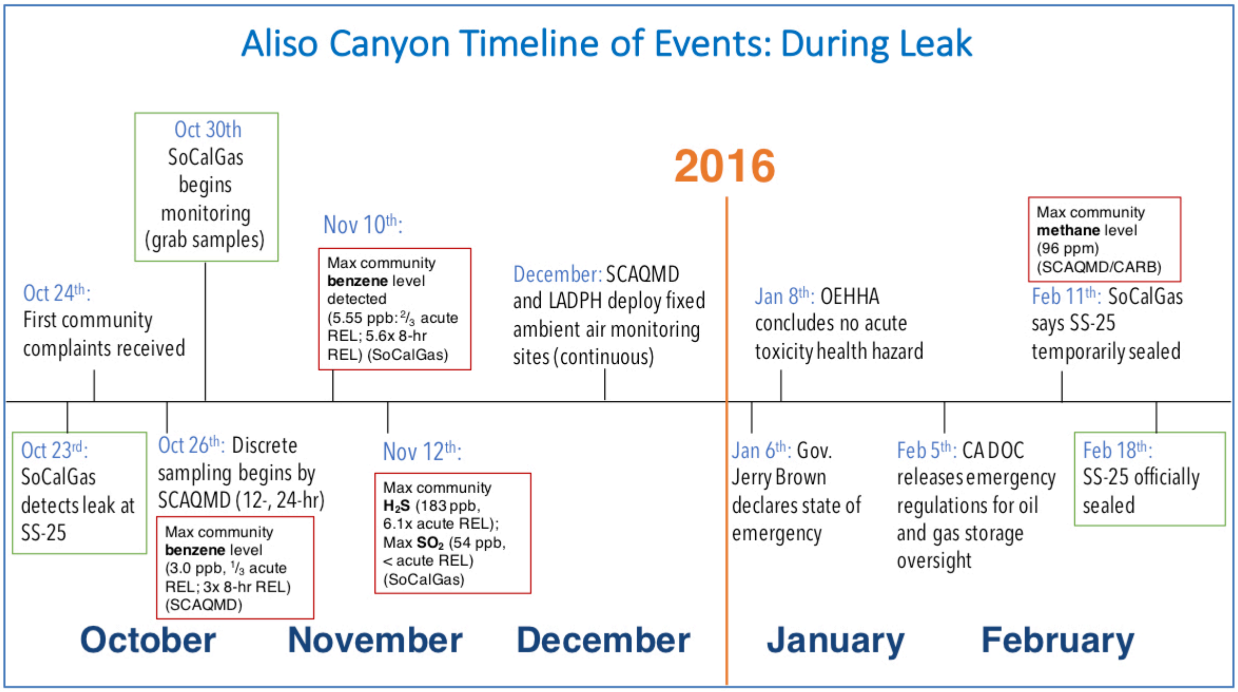


Figure 1.4-21. Aliso Canyon SS-25 Well Blowout Timeline of key events, monitoring moments, and regulatory determinations.

1.4.10.2 Air and Environmental Monitoring Data Collected in Response to the SS-25 Well Blowout

In response to the SS-25 well blowout, several entities carried out two primary categories of environmental monitoring: (1) outdoor air quality monitoring, and (2) indoor air and dust monitoring. Human exposures to toxic air pollutants by an outdoor emission source are not necessarily restricted to the outdoor environment, or even just to inhalation pathways.

We first describe the outdoor ambient air quality monitoring during and after the SS-25 blowout. This assessment includes discussion of:

1. The air pollution and other environmental monitoring conducted during and after the SS-25 blowout
2. The results of studies that assess the health symptoms of people in the Porter Ranch, CA, community during and after the SS-25 well blowout
3. Gaps in our understanding of the human health dimensions of this event

1.4.10.3 Air Quality Monitoring During and After the SS-25 Blowout

The blowout of the SS-25 well at Aliso Canyon set off a large number of air quality monitoring efforts headed by the gas storage operator, Southern California Gas Company (SoCalGas), by state agencies, universities, private citizens, law firms, and beyond. Table 1.4-16 lists the range of entities involved in the collection of ambient air pollutant concentration data during and after the 2015 Aliso Canyon incident, as well as the array of monitoring approaches and analytes of focus. It is important to note that there were more monitoring efforts focused on methane, which are excluded from this list but explained in detail in Section 1.5 of this report. For example, UC Davis, NASA, and CARB focused on the collection of methane emissions and atmospheric concentrations. Again, it is important to note that if we had access to the composition of Aliso Canyon UGS stored gas down to the parts per billion by volume concentration, we would be able to exploit the correlation of methane with concentrations of specific compounds in the gas of concern (e.g., benzene) to make inferences about the concentration of specific toxic air pollutants when only methane measurements were available. Unfortunately, without these composition data it is not possible to make these interferences with any certainty.

Table 1.4-16. Entities monitoring for air quality (excluding methane) during and after the SS-25 blowout.

	Agency[1]	Start Date	End Date	Analyte(s)[2]	Sample Type	# Sites	Location
During Active Blowout	SoCalGas	10/30/15	3/11/16	17 compounds	Grab	38	Porter Ranch/SS-25
	SCAQMD/CARB	12/16/15	TBD	64 compounds	Trigger/Grab	2	Porter Ranch
	SCAQMD/CARB	12/21/15	12/26/16	56 compounds	24-hr	4	Porter Ranch/Reseda
	UCLA/Jerrett	1/13/16	2/25/16	NO_x, CO_2, tVOC, PM	Continuous	6	Porter Ranch/Northridge
	UCLA/Jerrett	1/13/16	2/12/16	25 VOCs	Passive Sampler	24	Porter Ranch/Northridge
	CARB	1/14/16	7/21/16	Benzene	Hourly	1	Site 5 (34.294993, -118.558115)
	SoCalGas	1/11/16	2/3/16	17 compounds	12-hr	13	Porter Ranch/SS-25
	SCAQMD	2/2/16	7/19/16	Benzene	Hourly	1	Site 7 (34.26140, -118.594)
Post-Active Blowout	SCAQMD/CARB	2/26/16	2/24/17	H_2S	Hourly	1	Site 3 (34.293563, -118.580401)
	LACDPH	3/25/16	4/6/16	250 compounds	24-hr (summa)	210	Porter Ranch/Northridge
	LACDPH	3/25/16	4/8/16	86 compounds	Wipe	210	Porter Ranch/Northridge
	LACDPH	4/20/16	4/20/16	187 compounds	Soil	5	SS-25

1 SCAQMD – South Coast Air Quality Management District; CARB – California Air Resources Board; UCLA/Jerrett – University of California, Los Angeles – Michael Jerrett; LACDPH – Los Angeles County Department of Public Health

2 NO_x – nitrogen oxides; CO_2 – carbon dioxide, tVOC – total volatile organic compounds, PM – particulate matter; VOC – volatile organic compounds; H_2S – hydrogen sulfide

The SS-25 well blowout began on October 23, 2015. Unfortunately, there was no air quality monitoring of this event by any entity until October 30, 2015—seven days after the gas leak commenced—when the SoCalGas began to collect short-term air quality "grab samples" of ambient air with summa canisters at a number of sites at the facility and in the nearby community of Porter Ranch, CA, every 12 to 24 hours (Table 1.4-16).

Below, we assess two datasets that are the most salient to the characterization of air quality during and following this loss-of-containment event: (1) the SoCalGas short-term air quality "grab" sampling (SoCalGas, 2016a), and (2) the South Coast Air Quality Management District (SCAQMD) trigger sampling (SCAQMD, 2017a).

The SoCalGas short-term "grab" air-sampling data contains air pollutant measurements conducted by SoCalGas from October 30, 2015, to January 23, 2016. While we have not been able to confirm the time duration that each "grab" sample was collected, multiple sources indicate that it was not longer than a period of 10 minutes (Interagency Task Force on Natural Gas Storage Safety, 2016; PEHSU, 2016). We focus on this dataset and time period specifically for many reasons. The short-term grab samples collected by SoCalGas are the most temporally relevant attempt to characterize air quality during the ramp-up to the peak emission rate from the SS-25 well and also represent the only air pollution monitoring during the decline in emission rates. Other ambient air pollution monitoring datasets that focus on later time periods may not be reliably calibrated to this time period, due to increased uncertainty in source, meteorology, and other factors. The primary focus of this assessment is the health hazards posed by toxic air pollutants of the most significant temporal period of the SS-25 blowout and the data gaps that remain.

The SCAQMD "trigger" sampling dataset is also important in that it contains two critical approaches and insights: (1) continuous methane monitoring and (2) a "triggered" grab sample when methane concentrations surpass 4 ppm ambient concentrations considered in the normal range in the South Coast Air Quality Management District (SCAQMD) jurisdiction. As such, it minimizes the possibility that high concentrations of compounds emitted from the Aliso Canyon facility were missed, with the assumption that methane can be an indicator of the emission of other toxic air pollutants; and also ensures that nonmethane VOCs will be speciated at times of high concentrations of atmospheric methane, to evaluate their contents, concentrations, and related hazards. However, as noted in Table 1.4-16, the trigger sampling did not commence until approximately two months after the LOC event began.

1.4.10.4 Background on the Rate of Emissions from SS-25

According to the California Air Resources Board (CARB, 2016a; 2016b), due to the depressurization of the gas storage facility as gas is emitted, the rate of flow of methane decreased substantially from when the acute blowout began on October 23, 2015, to when it peaked in late November 2015 (Figure 1.4-22). The range of methane leak rates over time is estimated to be from 58,000 to 20,000 kilograms/hour (kg/hr). Based on the rate of methane emitted as a proxy for the rate of emission of other associated air pollutants as scaled down by their individual concentrations, it is likely that the continuous monitoring that commenced later in the leak after December 2015 or January 2016 has limited utility for assessing atmospheric concentrations and human exposures to toxic air pollutants during the period of highest-rate leakage.

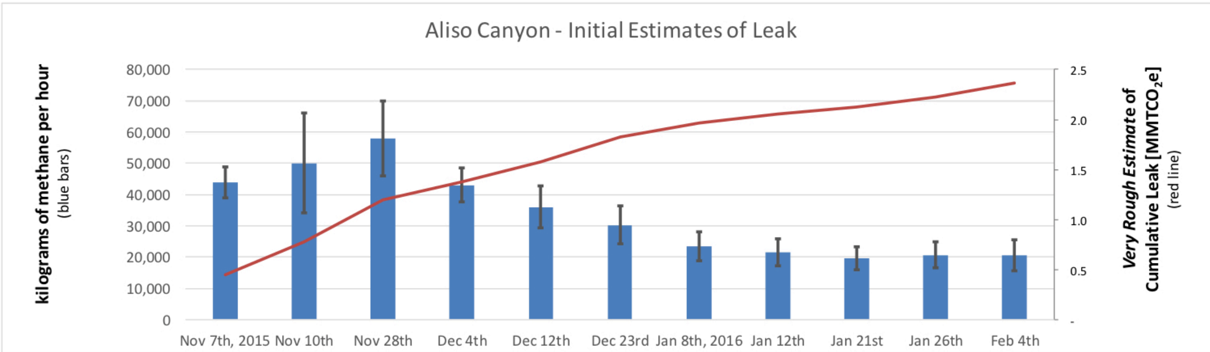


Figure 1.4-22. Rate and cumulative mass of methane emitted from the Aliso Canyon facility from November 7, 2015 to January 26, 2016. (CARB, 2016b).

1.4.10.5 Assessment of SoCalGas Short-Term Air Quality Monitoring Dataset

1.4.10.5.1 Approach to Assessment of SoCalGas Short-Term Air Quality Monitoring Data:

SoCalGas monitored 17 unique air pollutants in their short-term air sampling during the SS-25 blowout (methane, benzene, ethylbenzene, toluene, m&p-xylenes, o-xylene, carbon disulfide, carbonyl sulfide, dimethyl sulfide, hydrogen sulfide, ethyl mercaptan, isopropyl mercaptan, methyl mercaptan, propyl mercaptan, t-butyl mercaptan, sulfur dioxide, tetrahydro-thiophene). It should be noted that nearly half of these compounds are sulfur odorants. To make the decision as to which pollutants to focus on in this assessment, we used the following screening criteria:

1. **Reference Exposure Level Screen:** We screened each pollutant for its California Environmental Protection Agency (CalEPA) reference exposure level (REL). CalEPA RELs are pollutant concentrations at or below which adverse health effects are not likely to occur (U.S. EPA, 2015). For a full list of CalEPA RELs, please refer to OEHHA (2014). We included pollutants in this assessment if reporting in the SoCalGas short-term monitoring dataset indicated that the pollutant concentrations exceeded at least one half of the published CalEPA REL or air pollutant monitoring limits of detection were above the CalEPA RELs. From this screen, benzene and hydrogen sulfide (H_2S) came out as relevant. Benzene concentrations exceeded at least 50% of the CalEPA 8-hr and chronic REL (1 ppb, 3 ug/m^3) 112 times over the course of 74 days. It should be noted here that benzene emissions are likely associated with gas leaks from storage formations that have liquid hydrocarbons present, such as depleted oil wells as is the case in the Aliso Canyon UGS facility. Hydrogen sulfide, on the other hand, only exceeded 50% of the CalEPA REL (Acute REL: 30 ppb, 42 ug/m^3; Chronic REL: 8 ppb, 10 ug/m^3) twice between November 1, 2015 and January 12, 2016, but one of the times it reached a level of 185 ppb at a Porter Ranch community monitor, which is more than 600% of the acute REL.

2. **Commonly Reported Symptom Screen:** The most common symptoms that residents of Porter Ranch and surrounding areas have reported since the Aliso Canyon gas leak commenced are dizziness, headaches, general weakness, respiratory irritation, nausea, vomiting, abdominal discomfort, and epistaxis (nosebleeds) (LACDPH, 2016a). Most of these symptoms are consistent with—but not exclusive to—exposures to mercaptans and sulfur odorants (Behbod et al., 2014) with the exception of epistaxis. Based on this symptoms-based screen, we examine all mercaptans monitored for during the Aliso Canyon gas leak.

While some of the other compounds monitored were elevated above baseline or what is expected in Los Angeles, none reached the criteria above. It should be noted, however, that the emission of multiple air pollutant species at once or in close succession can introduce synergistic and additive effects beyond the influence of any one pollutant (U.S. EPA, 1986). Additionally, exposures to multiple sulfur compounds (e.g., hydrogen sulfide, sulfur dioxide, and the sulfur odorants (mercaptans), simultaneously or in close succession, may exacerbate and compound health impacts. Of course, emission of these air pollutants from the Aliso Canyon UGS Facility also entered the atmosphere with other air pollutants from other sources, potentially further compounding potential air-pollutant interactions and corresponding human health hazards.

Assessment of Benzene Monitoring Data

The Office of Environmental Health Hazard Assessment (OEHHA) under the California Environmental Protection Agency (CalEPA) has established benzene RELs for noncarcinogenic effects (reproductive/development, immune system, hematologic system, and nervous system) as:

- Acute (1-hour): 8 ppb (27 ug/m^3)
- 8-hour: 1 ppb (3 ug/m^3)
- Chronic: 1 ppb (3 ug/m^3).

Benzene is also identified as a carcinogen by OEHHA, IARC (the International Agency for Research on Cancer), and the World Health Organization (WHO). There is no level at which benzene exposure can be considered to be safe, although there are exposure levels for benzene that reflect de minimus risk (such as 1 in 100,000 lifetime added cancer risk). Even short-term exposures to benzene can be relevant for the development of childhood leukemias and other childhood cancers that may be initiated in-utero (Filippini et al., 2015; Zhou et al., 2014).

During the Active SS-25 LOC Event

The most elevated benzene concentrations in the community (not at the facility) found by the SoCalGas air monitoring data during the monitoring period were at the Highlands

Group (5.6 ppb) and the Porter Ranch Estates Group (3.68 ppb) monitors. Because all of the readings on the SoCalGas monitors are from grab samples—meaning only at one point in time—there is considerable uncertainty with respect to the duration of time for which these air pollution levels remain high or low. As such, the duration of time that benzene concentrations may have been elevated and contributed to acute (or chronic) exposures is not entirely clear. For instance, benzene concentrations at any concentration found using grab samples could mean that the concentration was steady for 60 seconds while the sample was being taken, or for 8 to 12 hours or more until the next sample was taken at the site, or a variety of other possible trajectories. Further, given the episodic nature of grab sampling, it is a possibility that samples taken during the day may not be representative of peak nighttime concentrations (Gifford, 1968) or vice versa.

SoCalGas air monitoring data indicate that benzene concentrations exceeded atmospheric concentrations for the 8-hour and chronic REL (1 ppb, 3 ug/m^3) 112 times at various monitoring sites during this short-term grab sampling. Measured exceedances of the 8-hour and chronic REL appear to be limited, with the majority of these exceedances in the community occurring before December 2016 (Figure 1.4-23). Of these 112 exceedances of the 8-hour and chronic RELs (measured concentrations ranged from 1.05 ppb to 5.6 ppb), 15 (13.4%) occurred in the Porter Ranch community, near homes and other places where people live, work, and play. The other 97 benzene REL exceedances were found at monitors on the property of the Aliso Canyon facility, reaching as high as 30.6 ppb, with a concurrent methane concentration of 1,747 ppm.

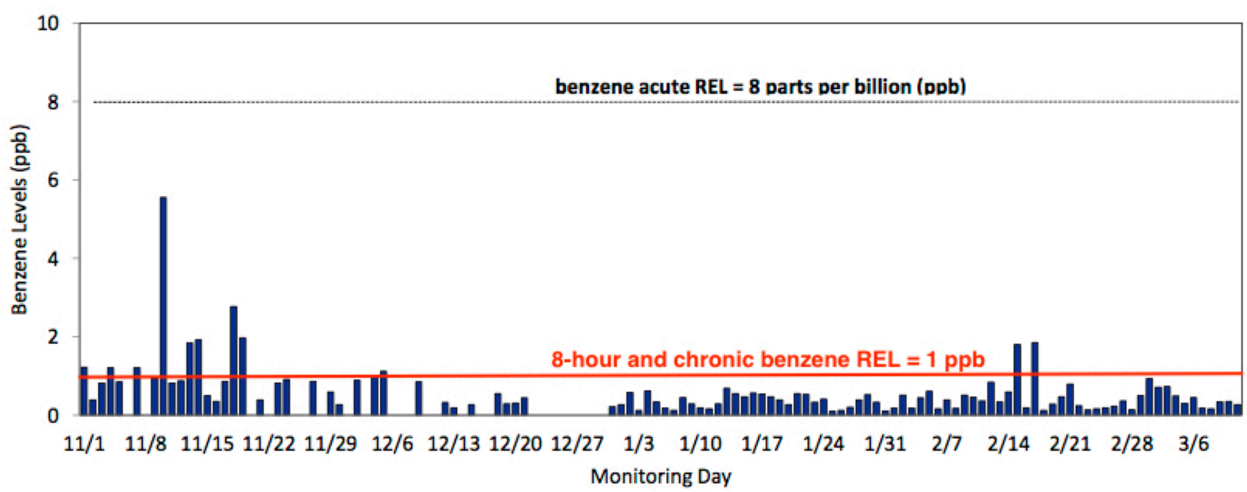


Figure 1.4-23. Highest benzene concentrations per day reported in the SoCalGas short-term sample dataset from November 1, 2015 to March 6, 2016. Please note that this figure only contains community benzene concentration measurements and not those at the facility. Source: Modified from OEHHA (2016).

The data presented in Figure 1.4-23 suggest that benzene concentrations are not high enough to warrant concern about acute exposures, and are not consistently elevated above 1 ppb to warrant concern over 8 hr and chronic exposures to the general population. However, while atmospheric concentrations of benzene in the community (not at the facility) may not have been elevated above the REL with significant frequency, there are a number of reasons why there is uncertainty in drawing a conclusion of limited health impact attributable to benzene:

1. From the commencement of community monitoring of the SS-25 gas blowout through January 11, 2016, benzene concentration data were collected using short-term grab sampling methods. As noted above, this type of sampling introduces uncertainty as to the duration for which these concentrations persisted in the atmosphere.

2. The use of inappropriately high limits of detection—or limits of detection above the REL—for many samples during benzene monitoring as discussed in the section below does not enable researchers to be able to determine with confidence that benzene concentrations were in fact low.

3. Air samples may have been diluted because of high concentrations of other air pollutants, in which case benzene could have been elevated or the other pollutants may have interfered with the ability to detect benzene (i.e., a matrix effect).

4. The "oily mist" emitted from the Aliso Canyon UGS facility discussed below induced a highly abnormal air-pollution monitoring environment and could have interfered with the ability of air pollution monitoring equipment to detect hydrogen sulfide and other pollutants.

High Limits of Detection for Benzene Introduce Uncertainty to Exposure

In addition to an assessment of reported benzene concentrations, it is important to take a close look at the limits of detection of the air monitoring equipment used to detect benzene in the air. If a limit of detection is above the concentration at which a pollutant is suspected to cause harm to human health in the general population, it is not possible to determine if the air pollutant in question is at a level where it does or does not pose a hazard to human health.

Of the 2,451 benzene concentration measurements taken by SoCalGas between October 30, 2015 and January 23, 2016, 467 (19%) of the samples used a limit of detection higher than the 1-hour and Cal/EPA 8-hour REL of 1 ppb (3 ug/m^3). Of these 467 samples, 259 (55.4%) were samples from the Porter Ranch community, where people live, work, and play, and not from the facility area. The limits of detection of SoCalGas air monitoring equipment that was above 1 ppb ranged from 1.1 ppb to 20 ppb.

Early on in the air-quality monitoring, there were 11 samples (0.4% of all samples with limits of detection above 1 ppb), which had a limit of detection of 20 ppb, more than 20 times the Cal/EPA REL. Of these 11 samples, two of them were in the Porter Ranch community at the Holleigh Bernson Park location, and the other nine samples were taken at the facility. These samples were collected on October 30, 2015, and October 31, 2015. It is not likely that benzene concentrations in the Porter Ranch community approached 20 ppb given the other data available, but the actual air-pollutant concentrations remain unknown during these early days of the leak, when emission rates were high.

In sum, from a limit-of-detection point of view, the scientific and regulatory communities as well as the public do not have sufficient information to know whether the benzene concentrations were below the acute, 8-hour, and chronic RELs early in the 2015 Aliso Canyon incident, and whether there were locations where benzene exposure could have risen to levels that could cause health effects.

Comparing Benzene Concentrations to the South Coast Air Quality Management District Annual Averages

To understand if there has been an increase in benzene concentrations in air resulting from the 2015 Aliso Canyon incident, it would be helpful to compare the current reported concentrations in the Porter Ranch area to baseline concentrations before the leak started. The best data for this comparison would be data collected prior to the leak in the same Porter Ranch locations where air monitoring was conducted after the leak. Unfortunately, this location-specific information (e.g., Porter Ranch benzene concentrations in air) is not available. However, there is another baseline dataset that can be used to shed light on benzene concentrations, namely the South Coast Air Quality Management District (SCAQMD) annual average concentration of benzene, reported through the Multiple Air Toxics Exposure Study (MATES). As discussed above and shown in Figure 1.4-23, higher benzene concentrations (>1 ppb) were reported at SoCalGas air monitoring sites in Porter Ranch following the SS-25 blowout relative to the <0.5 ppb MATES IV average reported benzene concentrations (see Figure 1.4-24; SCAQMD, 2015). If we assume the ambient Porter Ranch benzene concentrations to be similar to those at the Burbank MATES site, it is apparent from comparison of Figures 1.4-23 and 1.4-24 that benzene was elevated above average concentrations at Porter Ranch during the SS-25 well blowout. Note further that the MATES datasets reveal a significant reduction in ambient benzene concentrations between 2000 (MATES II) and 2015 (MATES IV), attributable to the reduction of benzene in gasoline.

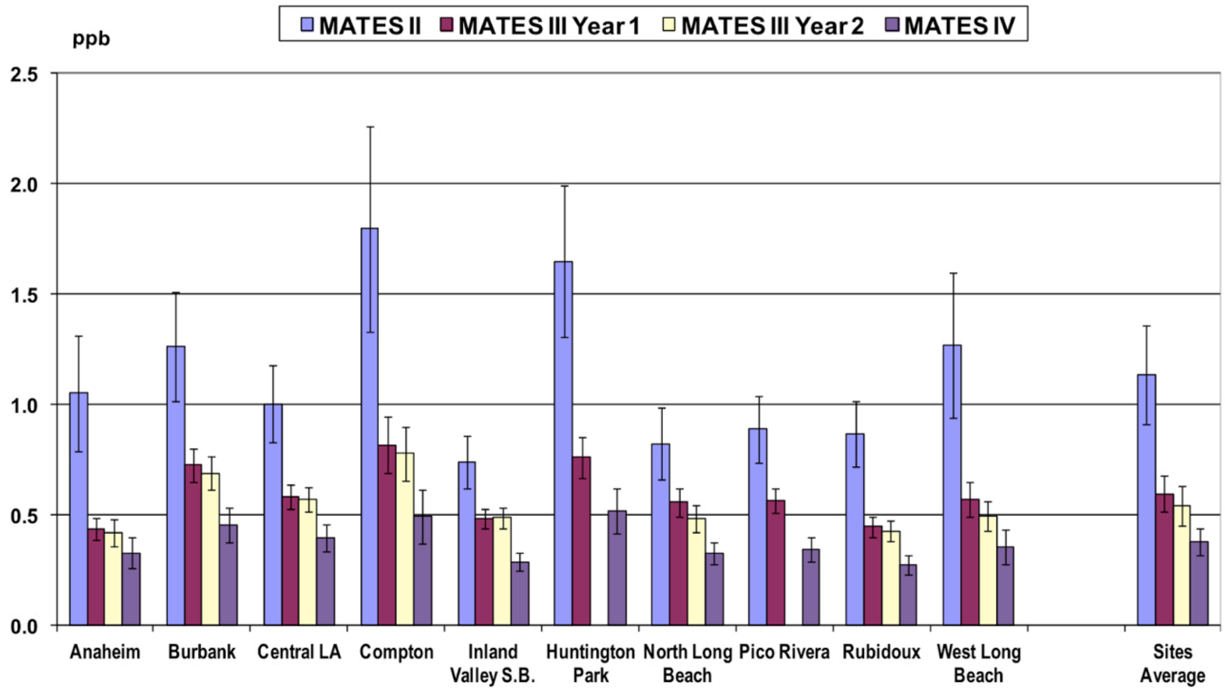


Figure 1.4-24. Average Benzene Concentrations in the Los Angeles Basin (SCAQMD, 2015).

1.4.10.5.2 Assessment of Hydrogen Sulfide Monitoring Data

The CalEPA RELs for hydrogen sulfide are reported as the following:

- Acute REL: 42 ug/m^3 (30 ppb)
- Chronic REL: 10ug/m^3 (8 ppb).

As described above in the case of benzene monitoring, because all of the hydrogen sulfide data are from grab samples—meaning only at one point in time—it is difficult to conclude with certainty the duration for which hydrogen sulfide levels are high or low, as the air pollutant concentration reported from the grab samples could have been the concentration for 60 seconds or up to 12 hours until the next sample is taken.

There are a few very elevated concentrations of hydrogen sulfide (H_2S) found at monitors operated by SoCalGas. However, there was one reading at a monitor at the Porter Ranch Estates Group that reported 183 ppb (more than 6 times the acute REL), a level that creates highly elevated acute toxicity risk to those exposed. Other noteworthy readings were at the Highlands Group and Porter Ranch School monitors at 16 ppb and 10.4 ppb, respectively.

The Porter Ranch School monitor's reading of 10.4 ppb H_2S occurred on Wednesday, November 17, 2015, likely while children were present. However, with the exception of the 183 ppb concentration noted at the Porter Ranch Estates Group monitor, none of the other grab samples reported concentrations that exceeded the acute REL (30 ppb).

Limits of Detection Issues for Hydrogen Sulfide

On the first three days of monitoring, across 36 samples (1.5% of all H_2S samples), SoCalGas used a limit of detection for H_2S of 50 ppb, or 1.7-times higher than the acute REL (30 ppb), and all samples came out as nondetects. Of these 36 samples, 14 were at the facility and 22 were in the community of Porter Ranch. Given that all but two grab sample readings following these days were below the acute REL (exceptions are the 183 ppb reading in Porter Ranch Estates Group and 29.1 ppb at the facility), it is unlikely that the concentration of H_2S was above the acute REL on these days, but it is very difficult, if not impossible to confirm.

Limits of Detection and Odor

It is important to note that not all of the concern regarding health effects from exposures to compounds can be determined by an exceedance of a REL. There is a heterogeneity and variation within and among populations that make some more susceptible to having physiological reactions to exposures than others. One form of physiological response is that to odor and in this way, the SoCalGas limits of detection for H_2S are not sufficient.

Hydrogen sulfide has a strong "rotten egg" odor that is often considered unpleasant and noxious. The odor threshold (the minimum concentration of a pollutant that the human nose can smell) of H_2S is 0.5 ppb, but the lowest limit of detection used by SoCalGas was 1.58 ppb, and most limits of detection used were 5 ppb and above. Thus, if the limit of detection is 5 ppb, people can be exposed to concentrations of H_2S up to 10 times the odor threshold while the monitor will report a "non-detect." Much like exposures to other sulfur compounds such as the mercaptans and other odorants added to gas (described below), people can respond very differently from one another to these smells. It is entirely possible that the nausea, headaches, vomiting, and other often-reported symptoms among those in proximity to the gas leak are reactions to elevated atmospheric concentrations of hydrogen sulfide.

Summary of Hydrogen Sulfide Monitoring Data

The monitoring data indicates that H_2S concentrations were elevated, in some cases significantly above the acute 8-hour REL, posing human health risks to populations that may have been exposed. Nevertheless, available data suggest that H_2S concentrations have not been regularly elevated above the acute REL (30 ppb) at the monitoring sites and there is little indication that H_2S concentrations were sustained above the chronic REL (8 ppb). As discussed above, the sampling design and equipment employed to monitor H_2S

concentrations prior to the commencement of the 12-hour and 24-hour sampling are unable to provide conclusive evidence that H_2S concentrations were above or below RELs with the exception of the moments that grab samples were collected.

1.4.10.5.3 Assessment of Sulfur Odorants (Mercaptans) Monitoring Data

Unlike benzene and hydrogen sulfide, mercaptans only have *occupational* exposure limits and do not have CalEPA-recommended community RELs. For instance, the NIOSH REL of 0.5 ppm (500 ppb) for most methyl mercaptans is the ceiling concentration determined in any 15-minute sampling period (OSHA, 2016). Outside of acute exposures in occupational settings—which are clearly inappropriate from a community exposure perspective—there is little guidance on safe levels of exposure.

The sulfur compounds, and in particular the odorants, are a likely cause of a number of the health complaints of residents living in proximity of the Aliso Canyon facility following the leaking of gas from well SS-25. The mercaptans in particular are known to elicit dizziness, headaches, general weakness, respiratory irritation, nausea, abdominal discomfort, and vomiting (Behbod et al., 2014).

There is only one study to date in the peer-reviewed scientific literature on potential community health effects of exposure to tert-butyl-mercaptan (TBM) (Behbod et al., 2014). The authors found statistically significant evidence that there are more self-reported health complaints closer to rather than further away from a mercaptan spill. Behbod and colleagues (2014) concluded that some of the factors that explain the health symptoms were likely due to the odor and the different sensitivities across the exposed population, and not necessarily attributable to actual physiological irritation caused by the mercaptans. While Behbod et al. (2014) assert that there are no long-term health implications of TBM exposure (at concentrations more elevated than at Porter Ranch), there are no longitudinal epidemiological data to support this claim.

The researchers made the following recommendations for future incidents when populations are exposed to elevated concentrations of mercaptans:

1. Health departments should prepare public health communication messages in advance to include strategies to minimize exposures (e.g., limit outdoor activity and keep windows closed in the evening and overnight hours).

2. Advise those with chronic respiratory and cardiovascular conditions to have their medications readily available.

Assessment of the SoCalGas Air Monitoring Data for Mercaptans

The odor threshold (the minimum concentration of a pollutant that the human nose can begin to smell) of tert-butyl mercaptan is 0.1 ppb, but the air monitoring equipment employed by SoCalGas had limits of detection well above this and up to 9.3 ppb (only one air sample used a limit of detection of 9.3 ppb), or 93 times the concentration at which the human nose is able to start to smell the skunk/rotten egg scent of mercaptans. Most of the limits of detection were not this high above the odor threshold, but 998 (43%) of all samples (2332) taken used a limit of detection at or above 5 ppb—at least 50 times the odor threshold. Of the grab samples that used limits of detection that were at or above 5 ppb, 493 (47%) were at monitors in the Porter Ranch Community, representing 20% of all TBM air samples taken.

Suggested Health Effects Evidence from Potential Increase in Epistaxis (Nosebleeds) Incidence

Anecdotally, there was an increased incidence of epistaxis in Porter Ranch and other areas near the Aliso Canyon facility during the 2015 Aliso Canyon incident. If there was truly an increase in incidence of epistaxis in these areas, it is probable that some other compound than the mercaptans was driving this trend. Of the compounds monitored for, hydrogen sulfide is a candidate (Mousa, 2015), but it could also be something else that is or is not currently being measured. Formaldehyde is also a candidate compound that may have been elevated in the atmosphere, given that methane can oxidize in the atmosphere and produce formaldehyde (Cicerone and Oremland, 1988). However, formaldehyde was not monitored in the ambient air during the SS-25 blowout.

1.4.10.6 Assessment of SCAQMD Trigger Sample Dataset

Description of SCAQMD Monitoring Approach

The South Coast Air Quality Management District (SCAQMD) collected air quality data via trigger samples beginning on December 16, 2015 through November 14, 2016 (SCAQMD, 2017). These trigger samples were taken by continually monitoring for methane; when the concentration of methane exceeded a certain threshold, it would "trigger" a canister sample that could be sent to the laboratory for chemical speciation. The analyses of the trigger samples focused on 64 chemical compounds.

Notable Results and Assessment of the Trigger Sample Dataset

The majority of the trigger samples did not find concentrations in exceedance of CalEPA RELs. However, a large proportion of the samples taken measured analytes at concentrations that exceeded normal ambient concentrations by an order of magnitude or more.

Also noteworthy is that a number of trigger samples had measured concentrations of benzene that were elevated substantially above the CalEPA REL. For instance, at the Highlands Pool monitor, seven out of the 92 VOC samples taken (7.6%) were above the REL, with the highest concentration measured at 13 ppb, which is 13 times the 8-hr REL (1 ppb, 3 ug/m^3) and 1.6 times the acute REL (8 ppb, 27 ug/m^3). Given that these are grab samples, it is highly uncertain how fast the concentrations of benzene returned back to normal ambient concentrations (0.1 ppb to 0.5 ppb). It is also noteworthy that the highest benzene concentrations found in the SCAQMD trigger sample dataset were measured after the SS-25 well was sealed, suggesting that the source of the benzene emissions was either from other infrastructure at the Aliso Canyon site, or from another source unassociated with the Aliso Canyon UGS facility.

The trigger sample laboratory analysis also included a metric called non-methane volatile organic compounds (NMVOCs). NMVOC is a coarse measure of organic compounds excluding methane in the air by weight. NMVOCs also include precursors for the atmospheric formation of tropospheric ozone, a strong respiratory irritant. While a high NMVOC value does not necessarily confirm that air is unhealthy or out of attainment from a regulatory perspective, it can be compared to the typical ambient air concentrations as an indicator of poor air quality. During the active SS-25 blowout, the NMVOC ambient concentrations during times that trigger samples were taken exceeded the normal ambient concentration range (100-700 ppb) in eight out of nine samples (89%) at the Porter Ranch Community School site; in 62/98 samples (63%) at the Highlands Community Pool site; and five out of ten samples (50%) at the Castlebay site. While it is likely that ethane, a relatively toxicologically inert compound prevalent in natural gas, may be one of the primary drivers for these atmospheric enhancements of NMVOCs observed in these samples, values that exceed normal ranges of NMVOCs in the atmosphere can be a proxy for other VOCs that potentially were not monitored, such as formaldehyde.

The trigger samples do not test for a number of important chemical compounds that are known to be associated with UGS and Aliso Canyon in particular. It is notable that these trigger samples do not include an assessment of sulfur odorants (e.g., mercaptans during the active SS-25 blowout phase). Also, given the small number of detections but very high observed concentrations of H_2S during the short-term air quality monitoring conducted by SoCalGas, it would have been helpful if this data collection effort had included H_2S.

Finally, formaldehyde associated with UGS is an intermediate in both the oxidation and combustion of methane. When produced in the atmosphere by the action of sunlight and oxygen on atmospheric methane and other hydrocarbons, its concentration in the atmosphere increases. According to reporting to the SCAQMD emissions inventory, Aliso Canyon is the largest single source of formaldehyde emissions in the SCAQMD during normal operations. While formaldehyde is likely emitted disproportionately by the operation of gas-powered compressor stations, the large amount of stored natural gas emitted into a relatively dense urban area could also contribute to the formation of locally elevated concentrations of formaldehyde in the area.

Also noteworthy is that following the sealing of the SS-25 well, 25 out of the 40 trigger samples (62.5%) were taken in the morning between the hours of 6:00 a.m. and 8:30 a.m. There are two potential factors that could explain why the majority of elevated methane concentrations were observed during this 2.5-hour period in the morning:

1. Meteorological: air pollutants tend to settle in the lower atmosphere, closer to ground level in the mornings and the evenings (Gifford, 1968).

2. Withdrawal of stored gas or other operations associated with emissions may be planned or often occur in the morning: the concurrence of elevated toxic air contaminant concentrations with elevated methane concentrations may signify that withdrawals or other activities that are associated with emissions to the atmosphere are occurring at the Aliso Canyon UGS facility at regular intervals.

If the reasons that methane concentrations were increasing were meteorological, then it would make sense that methane concentrations would also be elevated in the evenings. However, there is only one trigger sample in the SCAQMD dataset taken after the sealing of the SS-25 well that was in the evening (10:00 p.m. on July 10, 2016). As such, the temporal patterns of these data suggest that emissions may be occurring regularly in the mornings between 6:00 a.m. and 8:30 a.m. at the Aliso Canyon UGS facility. In order to confirm that this is indeed occurring, detailed information on scheduled stored gas withdrawals or activities involving emissions would need to be reported by the operator and made available for analysis.

If scheduled releases are indeed occurring, this may have implications for air pollutant concentrations on an intermittent basis for populations in proximity to UGS facilities statewide where these practices also may occur. Of course, Aliso Canyon is monitored far more extensively than any other UGS facility in the state, and so it is not yet possible to know whether episodic spikes in concentrations of methane and associated compounds in other communities near UGS facilities are actually occurring.

Limitations of Using Methane Concentrations as a Surrogate of other VOCs

The SCAQMD trigger samples rely on methane concentrations in the atmosphere to trigger further analysis of non-methane VOCs. The limitation of this approach is that it likely underestimates emissions of VOCs that are not co-emitted with methane. For instance, air pollution attributable to loss-of-containment of solvents, odorants, or other constituents stored in tanks will not be captured by this monitoring approach.

1.4.10.7 Review of Health Complaints in the Context of the Aliso Canyon Facility

Health Symptoms Survey Results

The first community complaint of symptoms was made on October 24, 2015, the day after the acute blowout at the SS-25 well commenced. The LACDPH conducted surveys of symptoms in the population surrounding the SS-25 blowout and after SS-25 was sealed. During the acute blowout, 81% of households surveyed reported symptoms (LACDPH, 2016a). The results of their follow-up survey after the SS-25 well was sealed indicated that 63% of sampled households continued to report health symptoms that they attributed to the

Aliso Canyon facility (LACDPH, 2016b). If this post-leak proportion is extrapolated across the population, it would mean that 4,800 households in the surrounding communities may have been experiencing symptoms after the well was sealed, at the time the study was undertaken in April 2016. The LACDPH also reported that several weeks after sealing well SS-25, the majority of households in the community had at least one household member that was still experiencing symptoms.

LACDPH found spatial trends in the distribution of symptoms and health impact survey results. As can be seen in Figure 1.4-25, which is a visual representation of health complaints per unit area, while positive symptom reporting was distributed throughout Porter Ranch and to a lesser degree in neighboring communities, positive symptom findings were concentrated closer to the Aliso Canyon UGS facility.

While self-reporting may over- or underestimate the true prevalence of health symptoms, these health symptom data were assessed in the context of other data that enable a more reliable understanding of the prevalence of these health symptoms in the populations. Of note is that symptom complaints during the SS-25 well blowout and after the plugging of the well were reported beyond 10 km from the SS-25 well (Figure 1.4-26) (LACDPH, 2016c).

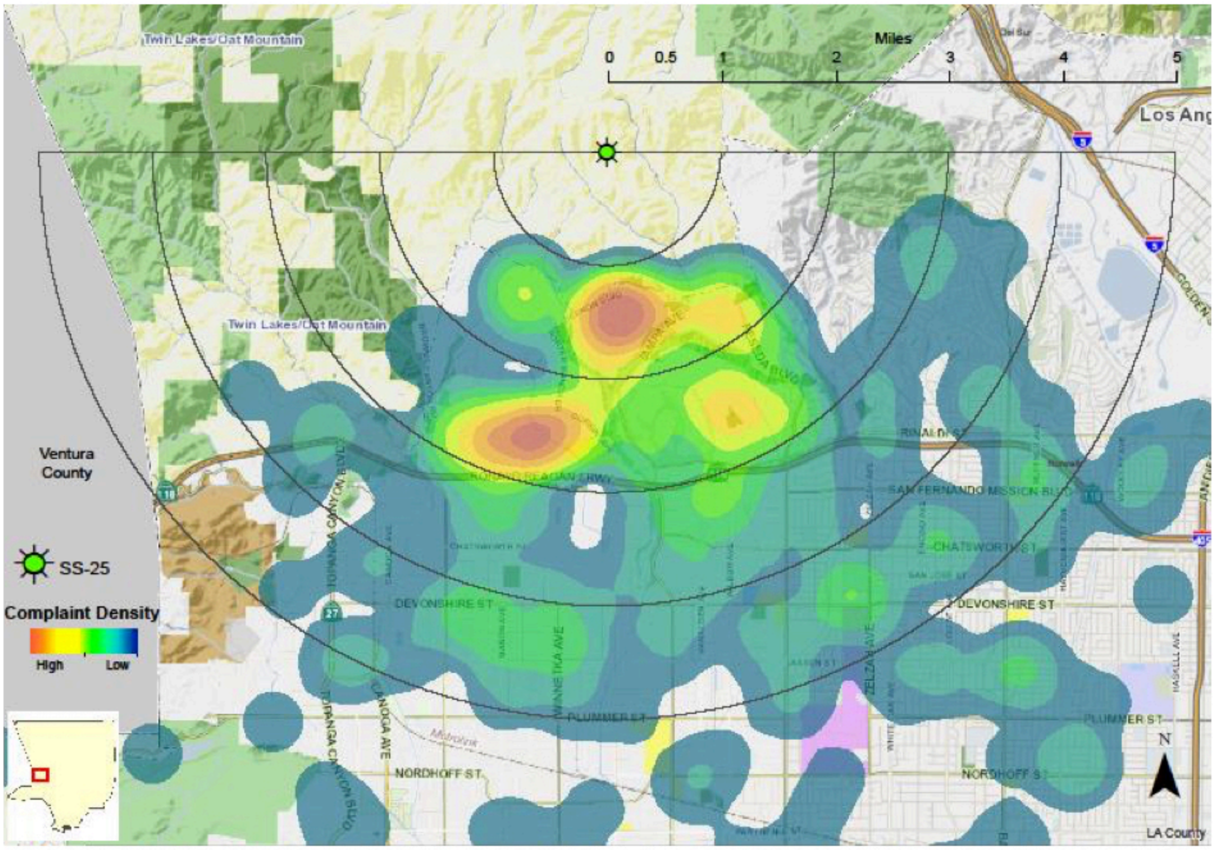


Figure 1.4-25. Aliso Canyon symptoms by respondent's address: complaint density. Created by the Office of Health Assessment and Epidemiology, Epidemiology Unit. 02/03/16. Map shows the density of symptoms by respondent's addresses. 511 of 687 addresses were located (the rest were excluded due to incorrect or missing addresses). (LACDPH, 2016c).

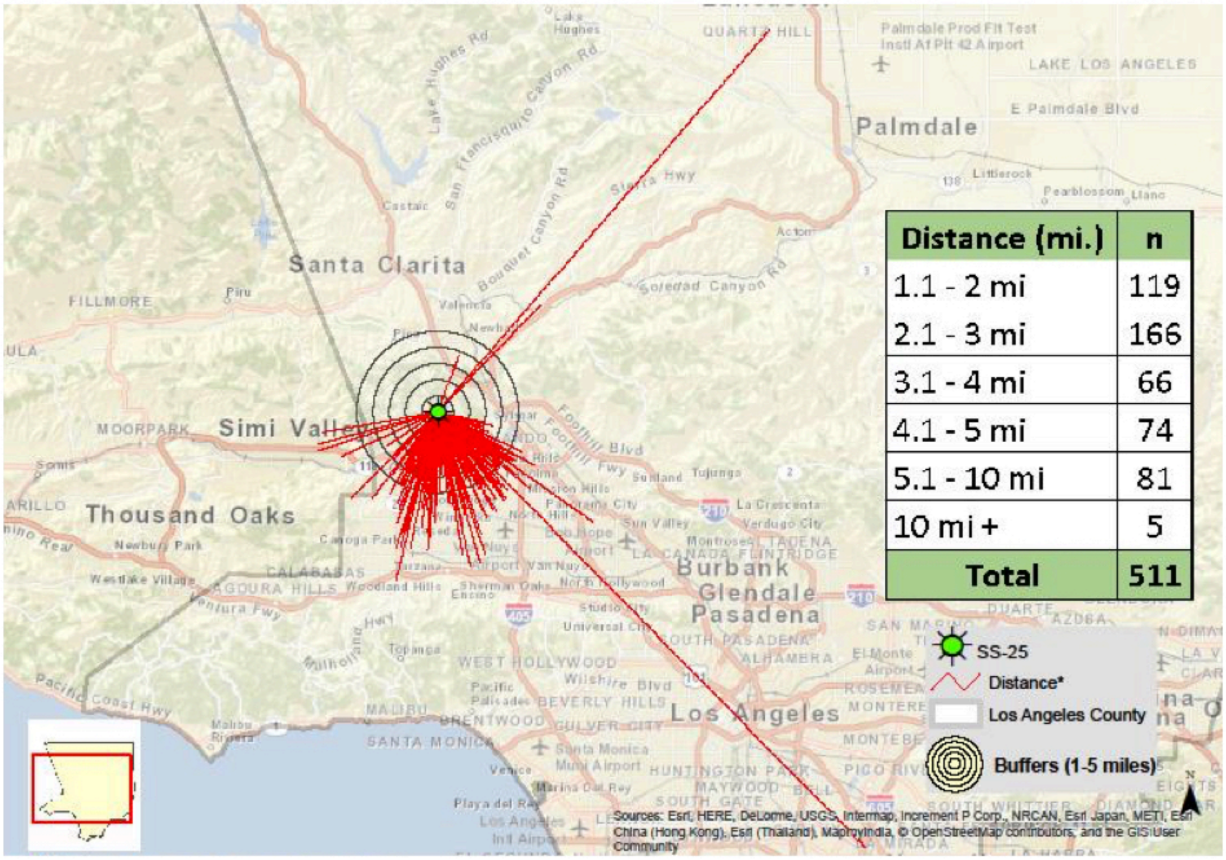


Figure 1.4-26. Aliso Canyon symptoms by respondent's address: Euclidean distance from the SS-25 well. Created by: Office of Health Assessment and Epidemiology, Epidemiology Unit. 02/03/16. Map shows the density of symptoms by respondent's addresses. 511 of 687 addresses were located (the rest were excluded due to incorrect or missing addresses). (LACDPH, 2016c).

LACDPH (2016e) conducted multiple health symptom surveys of households in proximity to the Aliso Canyon UGS facility during the SS-25 blowout and after the well was successfully plugged. The survey results during and after SS-25 LOC event can be found in Table 1.4-17. Also, as seen in Table 1.4-17, during the active SS-25 well LOC event, a projected 6,278 households, or 81% of the total household population in Porter Ranch and Granada Hills, likely were suffering from at least one health symptom attributable to the Aliso Canyon facility (LACDPH, 2016e). After the LOC event at SS-25 was stopped, LACDPH estimated that 4,801 households, or 63% of the total household population in Porter Ranch and Granada Hills, likely were still suffering from at least one health symptom attributable to the Aliso Canyon facility (LACDPH, 2016e).

Table 1.4-17. Households reporting that any member of the household experienced any of the following health symptoms believed to be related to the 2015 SS-25 well blowout weighted to the entire sampling frame, Porter Ranch and Granada Hills, CA, March 2016 (LACDPH, 2016e).

	During active gas leak			After well was sealed		
	Number of households (n=210)	Projected number of households (n=7,755)	Weighted % of households (95% CI)	Number of households (n=210)	Projected number of households (n=7,755)	Weighted % of households (95% CI)
Any symptom(s)	170	6,278	81.3 (75.5 – 87.2)	130	4,801	62.5 (56.3 – 68.7)
Eye, nose and/or throat irritation	153	5,650	73.9 (67.2 – 80.6)	123	4,542	59.1 (52.6 – 65.7)
Headache/migraine	148	5,465	71.8 (65.3 – 78.4)	108	3,988	51.9 (45.0 – 58.9)
Respiratory complaint*	138	5,096	67.0 (60.6 – 73.3)	105	3,878	50.7 (44.1 – 57.4)
Stress	123	4,542	60.0 (52.4 – 67.6)	88	3,250	42.9 (36.1 – 49.8)
Dizziness/light headedness	121	4,468	59.9 (53.1 – 66.7)	81	2,991	39.9 (33.5 – 46.3)
Nausea/vomiting	112	4,136	54.4 (48.2 – 60.5)	83	3,065	40.7 (34.3 – 47.0)
Nosebleed(s)	97	3,582	46.9 (40.2 – 53.6)	64	2,363	30.9 (24.4 – 37.4)
Skin rash/irritated skin	95	3,508	46.1 (38.6 – 53.6)	76	2,807	37.3 (31.0 – 43.5)
Diarrhea	55	2,031	27.0 (21.1 – 32.8)	44	1,625	21.7 (15.5 – 27.8)
Fever	32	1,182	16.0 (10.7 – 21.3)	26	960	12.9 (8.7 – 17.1)

Note: Excluded missing during gas leak: any symptom (n = 1); eye, nose and/or throat irritation (n = 1); headache/migraine (n = 1); respiratory (n = 1); stress (n = 1); dizziness (n = 2); nausea/vomiting (n = 2); nosebleeds (n = 1); diarrhea (n = 2); fever (n = 3) and don't know: eye, nose and/or throat irritation (n = 2); headache/migraine (n = 3); respiratory (n = 3); stress (n = 4); dizziness (n = 6); nausea/vomiting (n = 2); nosebleeds (n = 2); skin (n = 3); diarrhea (n = 4); fever (n = 7). Excluded missing after leak: nausea/vomiting (n = 1); and don't know: any symptom (n = 2); eye, nose and/or throat irritation (n = 2); headache/migraine (n = 2); respiratory (n = 3); stress (n = 5); dizziness (n = 7); nausea/vomiting (n = 5); nosebleeds (n = 3); skin (n = 6); diarrhea (n = 8); fever (n = 8). (LACDPH, 2016e).

These health symptoms reported to the LACDPH during the leak event, as well as after the SS-25 well was sealed, are consistent with exposures to mercaptans used as odorants. There are, however, exceptions to this, including – as noted above - the high reporting of epistaxis (nosebleeds), as mercaptans are not associated with increased incidence of nosebleeds in populations. For example, a symptom survey in one of the largest population exposures to tert-butyl mercaptans - one of the four mercaptans added to natural gas in the Aliso Canyon facility - during a spill in Alabama did not find that nosebleeds were being reported with any frequency, even though levels of this mercaptan were much higher than during the 2015 Aliso Canyon incident (Behbod et al., 2014).

The LACDPH conducted a health symptoms survey of households in Porter Ranch, CA, in the month after the SS-25 well was sealed. The results of this survey and the widespread prevalence of health symptoms that residents attributed to the leak are noteworthy given that outdoor ambient concentrations of methane, the primary constituent of natural gas, had come down considerably towards baseline, and the acute, high-rate emissions from the SS-25 well were determined to be low again.

Reported Community Health Symptoms and Visuals of "Black Oily Substance" Guide Environmental Monitoring to the Indoor Residential Environment

After the SS-25 well was sealed, the majority of households near the Aliso Canyon UGS facility reported experiencing health symptoms (LACDPH, 2016e). The LACDPH (2016d) reports that these symptoms are likely related to the 2015 Aliso Canyon incident and/or other emission sources from the Aliso Canyon UGS facility (LACDPH, 2016e). Given the ongoing health symptoms and their temporal and geographic association with the Aliso Canyon facility and the SS-25 blowout in particular, the LACDPH launched an indoor-environment testing investigation. The high-level conclusions of this investigation are summarized below, with our further assessment of the data and results listed below that.

After the SS-25 Well is Sealed: LACDPH Conclusions of Resident Symptoms Reporting and Indoor Environment Testing

LACDPH conducted an indoor assessment of contaminants related to natural gas and oil emissions, and a comprehensive investigation of reported symptoms after the gas leak was sealed. The results of this LACDPH (2016d) assessment are quoted below:

1. The majority of households near the Aliso Canyon Storage Facility experienced health symptoms after the well was sealed, and these symptoms were likely related to the gas leak and/or other emission sources from the Aliso Canyon UGS facility.

2. Barium and several other metal contaminants found in household dust are common additives in the drilling and well-kill fluids used at the Aliso Canyon UGS facility. The findings suggest that metals were emitted during the leak and may have been distributed into the surrounding area and into the homes of residents. Metals in household dusts can cause respiratory and skin irritation, and could be contributing to reported symptoms.

3. Overall, the indoor air testing did not detect chemicals at levels that present an elevated health risk. The occurrence of indoor air contaminants within the study area was found to be generally consistent with both the comparison area and with published background data on air contaminants in residential settings.

4. Adequate ventilation of homes to flush out residual contaminants, deep cleaning of surfaces, regular change-out of HVAC filters, and proper maintenance of air purifiers will minimize the potential for exposure that may produce symptoms. Such cleaning will also remove routine dust, pollens, and molds that may have accumulated during the period when people were not residing in their homes and practicing normal house cleaning.

5. It is possible that other contaminants from the leak site and/or other sources are present in the homes and the ambient air. For example, the Aliso Canyon UGS facility is the largest single emitter of formaldehyde in the South Coast Air Quality Management District, releasing ~14,054 pounds per year. SCAQMD reported that formaldehyde was not found at elevated concentrations in the community during the gas leak; however, DPH will continue to consult with experts to monitor this issue.

6. Ongoing monitoring by CARB and SCAQMD indicates that methane levels in the area around the Aliso Canyon UGS facility continue to be higher than expected and may indicate some additional source of methane in the area. Although these methane levels are not as high as during the leak periods, the elevated levels do indicate the need for continued monitoring. DPH will continue to work with its partners to understand why methane levels continue to be above normal at times.

As noted above by LACDPH, even after the successful sealing of the SS-25 well when the rate of gas emissions from this site dropped dramatically (Figure 1.4-17), the LACDPH Community Assessment for Public Health Emergency Response (CASPER) study reported that health symptoms among residents moving back to their homes were still very prevalent. This finding led the LACDPH to consider other environmental pathways and routes of exposure, and specifically to consider the possibility that the insides of residences might hold sources of health-damaging exposures, or at least exposures that were causing deleterious health symptoms in residents.

Other key signs that the indoor environment might contain exposures sourced from the Aliso Canyon facility potentially responsible for the health effects reported by residents was visible black oily substances deposited both on private property outdoors (on cars, walkways, windows, pools) as well as indoors on countertops and elsewhere. This black substance on the homes of people in Porter Ranch demonstrates substances from the Aliso Canyon facility were atmospherically transported and deposited on and into places where people live, work, and play.

Composition of the Black Substance Deposited on Porter Ranch Residential Properties Including Inside of Homes

It is highly likely that this "black" substance originated from the SS-25 well site at the Aliso Canyon UGS facility. The substance includes, but is not identical to, the heavy drilling muds used in the multiple attempts to kill the SS-25 well to stop the leak (see discussion of kill attempts in Sections 1.1 and 1.2 of this report). Shortly after complaints that this substance was being deposited on and inside of homes, cars, and other areas, SoCal Gas set up nets to capture this black substance by agglomeration as it was being emitted through craters adjacent to the well. Below are some considerations that are important to consider with respect to the composition and potential human exposures to this substance.

While this substance has been referred to as “crude oil” and “heavy drilling muds” in some news media accounts, it is not entirely clear what this substance actually consists of. It is very likely that crude oil (which in itself is a mix of sometimes hundreds of petroleum hydrocarbons and other solid, liquid, and volatile constituents) is a component, given the fact that the Aliso Canyon facility is a depleted oil field, and oil is still produced from shallower reservoirs above the gas storage reservoir (see Section 1.1 of this report). However, it is unclear what the full chemical profile of this substance is and where its constituent compounds, naturally occurring or otherwise, may have originated. Given that the substance was emitted from Aliso Canyon, possible sources of other compounds that are likely to have been intermingled with this oily mist include:

- **Naturally occurring chemical constituents that are not crude oil**: Crude oil and associated fluids contain naturally mobilized chemical constituents including heavy metals, volatile organic compounds (VOCs), naturally occurring radioactive materials (NORMs), salts, and other compounds that are well known to be present, sometimes in elevated concentrations.

- **Chemical additives related to historic and recent well stimulation and other oil and gas development and maintenance**: Prior to the use of Sesnon-Frew reservoir at Aliso Canyon for natural gas storage, it was a productive oil field. Many chemical constituents are used routinely to maintain and clean out wells, and these same chemicals may also be used to stimulate and enhance oil and gas production (Stringfellow et al., 2017). Some of these chemicals remain in the subsurface and can be emitted during a blowout such as the 2015 Aliso Canyon incident. More than half of the wells put into operation in the Aliso Canyon UGS reservoir in the last 20 years have been hydraulically fractured (CCST, 2015b). The relatively small sand mass or fluid volume used in each of these operations, as reported in the record available for each well, suggests they were “frac packs,” the purpose of which was likely to increase the peak gas delivery rate.

- **Synergistic Chemical Constituents**: Chemical additives that are added to wells can co-mingle with compounds that are naturally occurring in the formation. Under elevated temperature and pressure, some of these compounds can undergo reactions and create new compounds with unknown human health and environmental profiles. To date, there are no data available on these synergistic chemical constituents or clear evidence that they are in the black substance that has been deposited in the Porter Ranch community as a result of the SS-25 well blowout.

Other toxicological and exposure considerations of this oily black substance that remain unknown to date include:

Aerosolized Particle-Size Considerations

It would be helpful to know the range of particle sizes of the aerosolized "oily mist" when it was suspended in and transported through the atmosphere. Particle size is important, because respiratory exposures and their health consequences are more elevated when people are exposed to particles less than 10 micrometers (μm) in aerodynamic diameter ($<PM_{10}$). Particle size matters because particles larger than PM_{10} tend not to pass beyond the nose, while those between $PM_{2.5}$ and PM_{10} penetrate to the upper respiratory tract (nose, throat, bronchi), while particles smaller than 2.5 μm in aerodynamic diameter are able to penetrate deeper into the lung to the alveoli (U.S. EPA, 2017a).

Environmental Degradation Considerations

As noted, total petroleum hydrocarbons (TPHs) can represent hundreds of chemical compounds, and many of them degrade relatively rapidly in the environment. As such, it would be helpful to know the duration of time between the deposition of these droplets on people's property and when the samples of these droplets were tested in the laboratory.

Below, we describe an indoor environmental quality investigation undertaken by the LACDPH and researchers at UCLA and UC Berkeley to answer some of these questions. The investigation included taking "swab samples" of indoor dust on countertops and other surfaces to determine the presence of potentially health-damaging and symptom-inducing compounds that could explain the ongoing symptoms reported by residents upon returning to their homes.

Implications of Indoor Metal Testing Findings in Swab Sampling

In this study, LACDPH sampled and evaluated dust wipes from 114 homes and two schools. Thirteen of the 16 metals tested for in the surface-wipe samples of household dust were detected in Porter Ranch homes, while only four of the 16 metals were found in the control homes outside of the Porter Ranch area. The most frequently detected metal in the samples was barium, which was found in 19% of the Porter Ranch homes in concentrations from 0.05 to 1.0 ug/cm^2, levels higher than in the control homes. Other metals identified in the study (aluminum, cobalt, iron, manganese, nickel, strontium, and vanadium) were also higher in Porter Ranch homes than in the group of control homes (Figure 1.4-27). These results act as a sort of "fingerprint" of substances that entered the indoor environment in Porter Ranch.

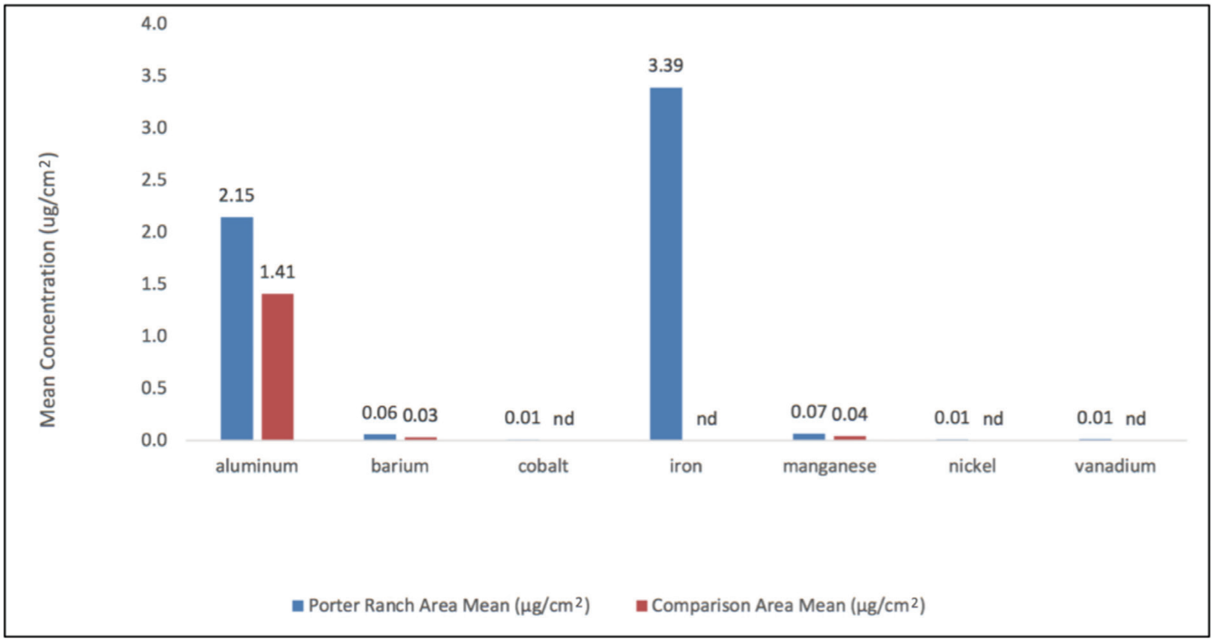


Figure 1.4-27. Average metal concentrations in surface wipe samples (ug/cm²)—Porter Ranch area homes and schools, and comparison area. (Source: Beckerman and Jerrett, 2016).

Additionally, further analyses conducted by UCLA researchers indicate that there is a very high correlation between the presence of these metals in homes in Porter Ranch compared with the control (Beckerman and Jerrett, 2016). Further, given that barium sulfate was known to be used in the drilling muds that were used in the attempt to kill the SS-25 well blowout, the high correlation between metals, oily residues, and barium sulfate in Porter Ranch homes compared to the control homes outside of Porter Ranch provides strong evidence that contaminants and other materials sourced from the Aliso Canyon facility penetrated the inside of homes.

In summary, the findings above build upon one another to provide important information about potential health risks from exposure:

Source Attribution: As noted above, findings from this indoor environment study indicate that there was a clear environmental pathway through which contaminants—originating from the 2015 SS-25 blowout—could enter the indoor environment of homes downwind of the facility. These contaminants include compounds in stored gas from the facility and compounds used to kill the well, indicating that methods used and overall ability to stop a leak must be taken into account when considering potential health risks to nearby populations.

Uncertainties about Chemicals of Concern: There is strong evidence that metals from the Aliso Canyon facility penetrated the indoor environment of the Porter Ranch homes downwind of the SS-25 well, but there remains uncertainty as to whether other *unmonitored contaminants* could have penetrated the indoor environment as well. The LACDPH identified the following as priority chemicals of potential concern based on "available information": sulfur compounds, benzene, and other VOCs, barium, petroleum hydrocarbons, and polycyclic aromatic hydrocarbons" (LACDPH, 2016c) Given the widespread historical and current chemical usage during activities in oil and gas wells—and by default in depleted oil reservoirs used for natural gas storage—this list of chemical constituents may be overly narrow, especially given the extent of the reported health symptoms in the Porter Ranch community. *To address this concern, it would be helpful for SoCalGas to disclose chemicals used in the Aliso Canyon field—and in what mass and frequency—to the LACDPH and the research community in order to better set priorities for monitoring.*

Table 1.4-18. Summary of chemicals of concern that LACDPH used for monitoring of indoor Porter Ranch environments after the SS-25 well was sealed (LACDPH, 2016c).

Compound(s)	Potential Source	Data Supporting Compound as a Potential Source
Sulfur compounds	Odorants & Reservoir	Soil near SS-25, air downwind of SS-25, ambient air
Benzene, toluene, ethylbenzene and xylenes (BTEX)	Reservoir	Soil near SS-25, air downwind of SS-25, ambient air
Barium	Well kill mud	Material safety data sheets, Soil near SS-25, air downwind of SS-25
Petroleum Hydrocarbons	Reservoir & Well kill solutions	Material safety data sheets, Soil near SS-25, air downwind of SS-25
Polycyclic Aromatic Hydrocarbons (PAHs)	Reservoir	Soil near SS-25, air downwind of SS-25
1,2,4 Trimethylbenzene	Reservoir	Soil near SS-25, air downwind of SS-25
Crystalline Silica	Well kill solids	Material Safety Data Sheets

Other potential sources of toxic compounds: Chemicals used by UGS facilities

While chemicals used in oil and gas production during routine activities (e.g., drilling, routine maintenance, completions, well cleanouts) and well stimulation (e.g., hydraulic fracturing and acid stimulation) are reported for all other wells in the South Coast Air Quality Management District (SCAQMD, 2013, rule 1148.2; Stringfellow et al., 2017), no such disclosures are made for UGS wells. This is true for UGS facilities statewide. UGS operators disclose chemical information to the California Environmental Reporting System (CERS) for chemicals stored on-site; however, this information is not publicly available for all facilities, does not include what the chemicals are used for, or the mass or frequency of use on-site, and often lists product names without unique chemical identifiers (SoCalGas, 2015). As such, it is likely that on-site chemical use occurs, but the composition of those chemicals, the purpose, mass, and frequency of their use, and their associated human health risks during normal and off-normal events at UGS facilities remain unknown.

1.4.10.8 Aliso Canyon Monitoring and Emissions Inventory Reporting for UGS Facilities

As discussed in Section 1.4.5, UGS facilities report annual emissions for criteria and toxic air pollutants through the Air Toxics Hot Spots Program. While many pollutants emitted by UGS facilities were monitored for during or after the 2015 Aliso Canyon incident (Table 1.4-16), there are notable exceptions. Of all chemicals with unique chemical identifiers – or Chemical Abstract Service Registry Numbers (CASRN) – (i.e., excluding broad chemical groupings such as particulate matter) reported in the emissions inventory for Aliso Canyon (n=58), 18 (31%) were monitored for in air during or shortly after the SS-25 blowout. These compounds are listed in Appendix 1.C, Table 1.C-4. However, the majority of compounds historically reported as emitted from the Aliso Canyon UGS facility with CASRNs (69%) were not monitored for in air during or after the Aliso Canyon SS-25 blowout.

A few of these unmonitored compounds are particularly relevant due to the large estimated amount emitted and chemical-specific toxicity. Ammonia was not monitored for during or after the SS-25 blowout, but was consistently ranked in the top three emitted pollutants across all years of reported data (data not shown). Ammonia is associated with acute and chronic respiratory health impacts. Compounds emitted from Aliso Canyon with higher median annual emissions (<175 pounds/year) include acrolein (associated with eye and respiratory irritation) and methanol (associated with adverse effects on the nervous system and development), both of which were not monitored for during the Aliso Canyon blowout (Appendix 1.C, Table 1.C-4).

Facility-specific emissions inventories can be used to inform air and other environmental monitoring efforts near UGS facilities during routine operations as well as during and after large LOC events. Notably, many broad chemical groupings (excluded from unique chemical analysis above) are reported to emissions inventories but were not monitored for during and after the SS-25 blowout. For example, particulate matter (PM) and other secondary air pollutants are known to be directly emitted from UGS facilities and indirectly formed through atmospheric transformation processes and are associated with adverse health outcomes (Section 1.4.6.4.4).

There are also a few notable compounds that are not included in the emissions inventories, but that are particularly relevant when discussing health-relevant compounds associated with underground gas storage in California. Mercaptans are compounds added to odorize methane so that leaks and exposures can easily be detected. Mercaptans are not included on the list of substances required for reporting through the Air Toxics Hot Spots Program. Additionally, mercaptans do not have Cal/EPA community RELs, and only have occupational exposure limits. Outside of acute exposures in occupational settings, which are clearly inappropriate from a community health perspective, there is little guidance on safe levels of exposure. The sulfur compounds and in particular, the odorants are a strongly suspected cause of a number of the health complaints of residents living in proximity of the Aliso Canyon facility since the leak from well SS-25 began in October 2015 (see Section 1.4.10 below). Mercaptans in particular are known to elicit dizziness, headaches, general weakness, respiratory irritation, nausea, abdominal discomfort, and vomiting (Behbod et al., 2014).

1.4.10.9 Emerging Health Datasets and Reports Regarding the 2015 Aliso Canyon SS-25 LOC Event

There have been recent efforts by community members and others to conduct sampling of human hair, blood, and urine and environmental media to evaluate exposure and environmental contamination from the 2015 Aliso Canyon incident. A presentation by Dr. Jeffrey Nordella (2017) has reported some of these results but future work needs to be done to contextualize these results and to date there is not yet a written document to assess and the raw data are not publicly available. Future work should evaluate these data. New reports and publications related to the 2015 Aliso Canyon incident are expected in the coming months from LACDPH and UCLA (Personal Communication, Katherine Butler, LACDPH).

1.4.10.10 Aliso Canyon and Public Health: Discussion and Conclusions

The 2015 Aliso Canyon incident involving nearly four months of surface blowout of the SS-25 well, and all of the environmental monitoring that ensued provides an opportunity to evaluate the public health dimensions of this kind of large-scale disaster at a California UGS facility. The confluence of multiple datasets, including (1) air pollution and indoor environment samples, (2) the prevalence and geographic distribution of health complaints reported by the surrounding population, and (3) time-activity information on symptoms reporting strongly suggest that the cause of many of the health effects and symptoms reported by the nearby population were related to the Aliso Canyon UGS facility. However, as noted, the exact mechanisms that induce a number of these health effects and symptoms remain uncertain. It is highly likely that many of the symptoms experienced by the nearby population were induced by exposures to sulfur odorants (mercaptans). However, mercaptan exposures do not explain the high reporting of epistaxis (nosebleeds). Moreover, mercaptans also do not explain why the majority of households returning to their homes near the Aliso Canyon facility after the sealing of the SS-25 well complained of health symptoms.

The uncertainty with respect to which contaminants were the culprit of health symptoms reported by residents could be driven by multiple factors, including but not limited to:

1. The fact that air monitoring only focused on 24 of the 98 contaminants reported as emitted by UGS facilities statewide.

2. The possible use of hazardous chemicals in wells and associated infrastructure (e.g., for maintenance, well work-overs, well killing, and other purposes) that has not been disclosed and which could have been entrained in the gas, leading to human exposures. All oil and gas wells in the SCAQMD are required to disclose their chemicals use except for UGS wells pursuant to SCAQMD Rule 1148.2.

3. A chemical or groups of chemicals were released intermittently during the first part of the leak when only short-term grab samples were being collected and the presence of these compounds were missed by more continuous and thorough monitoring later on.

4. The possibility that interactions between multiple pollutants from the facility and possibly from other sources created a mixture of contaminants that induced health effects and symptoms in the population, but no one chemical was responsible for all symptoms.

5. The emissions of the compounds from the facility atmospherically transformed to other chemical species or particles that were not monitored for. Data collected on secondary formation of particles downwind of the Aliso facility during and after the leak by a team of researchers from UCLA and UC Berkeley (Jerrett and Garcia-Gonzales) may shed light on a part of this issue; however, their results have not been published as of the writing of this report.

Of course, many of the non-acute symptoms and health effects that take time to clinically manifest that are now being alleged will require retrospective and prospective public health and medical surveillance approaches to ascertain their association with the Aliso Canyon facility.

1.4.11 Occupational Health Dimensions of UGS in California

This section evaluates health and safety hazards relevant to on-site workers at UGS facilities in California, including employees and contracted or temporary workers. The assessment considers health and safety hazards associated with routine and off-normal emissions scenarios (e.g., the 2015 Aliso Canyon incident), and includes potential exposures to toxic air pollutants, fire, and explosions. The lack of data involving emissions, gas composition, and occupational air monitoring at California UGS facilities limited the scope and detail of this assessment. However, information was gathered from UGS site visits, operators, and state agencies. The protection of workers from these hazards would inherently provide better protection for the community, as workers are on the front line for most incidents.

1.4.11.1 Characterization of workers associated with UGS facility operations

UGS workers include both employees of the operating gas storage companies (e.g., SoCalGas and PG&E), and those provided by staffing agencies (i.e., "temporary workers") who are engaged in construction, routine operations, and non-routine operations. Temporary workers or contractors are especially at risk because they are often not covered by company health and safety plans; their exposures are usually not monitored; their numbers at any given time on site may not be known with precision; their presence on-site is often intermittent (but may include living on-site for days to weeks at a time); and they are sometimes called upon to perform highly specialized and high-risk tasks (e.g., killing a well blowout) as companies tend to contract out jobs associated with the highest exposures. The Occupational Safety and Health Administration (OSHA) and National Institute for Occupational Safety and Health (NIOSH) published recommendations on the necessity of protecting *all* workers:

> *"Whether temporary or permanent, all workers always have a right to a safe and healthy workplace. The staffing agency and the staffing agency's client (the host employer) are joint employers of temporary workers and, therefore, both are responsible for providing and maintaining a safe work environment for those workers. The staffing agency and the host employer must work together to ensure that the Occupational Safety and Health Act of 1970 (the OSH Act) requirements are fully met" (OSHA & NIOSH, 2014).*

During a site visit by our research team to the McDonald Island Underground Gas Storage Facility (see side bar below), we observed that the contracted or "temporary" workers were responsible for much of the above-ground well maintenance and monitoring operations. Along with the employees of UGS facilities, temporary workers should be included as much as possible in all evaluations of occupational human health and safety risks associated with UGS. As such, throughout this section, the term "workers" refers to both employees and contracted or temporary workers.

Side bar: McDonald Island Underground Gas Storage Facility Site Visit

In June 2017, CCST staff and the authors of this and other chapters in this report visited the McDonald Island Underground Gas Storage Facility, a Pacific Gas and Electric (PG&E) operated underground gas storage facility in Northern California. Prior to the visit, authors of this chapter gathered a list of questions specific to risks associated with UGS activities. The site visit included the following: (1) an overview of activities at McDonald Island and other PG&E operated gas storage facilities in Northern California; (2) a guided tour around the facility; and (3) opportunities to ask further questions. While questions specific to health and safety aspects associated with UGS were posed during the visit, many of these questions went unanswered. To our knowledge, PG&E staff did not follow-up with answers to questions that were documented in written form prior to the visit or questions asked verbally during the visit.

Although UGS facilities can cover relatively large geographic areas, we understand that relatively few workers are needed for the normal operations at these facilities and that employees include at least two system operators on each shift and numerous maintenance workers. During our site visit to the McDonald Island UGS Faciltiy, PG&E staff stated that there are typically four mechanics, six technicians, two assistants, two to four engineers, one full-time environmental specialist, and approximately 20 others on-site. From conversations with state agencies, we understand that SoCalGas has approximately 200 employees in total at their four UGS sites (Aliso Canyon, Playa del Rey, La Goleta, and Honor Rancho). However, the number of contractors on site is unknown and could equal or exceed the number of employees. Some contractors temporarily live on-site in travel trailers, and may be exposed during work and also during residence.

During our site visit to McDonald Island UGS Facility, we observed several contractor trailer residences on-site. Occupational exposure limit (OEL) standards are intended to protect workers from eight hours of exposure per day, with 16 hours away from exposure during which the body can recover and some materials can be metabolized and eliminated from the body (AIHA, 2017). For temporary workers living on site, OELs are therefore not applicable, and other exposure limit recommendations may be more appropriate. Furthermore, the OELs should be reconsidered carefully for those who work longer than eight-hour shifts, during which time recovery or elimination may not occur.

1.4.11.2 Review of Processes and Potential for Occupational Exposures

Routine exposures can occur from specific job tasks and from the continuous emissions from leaks (e.g., fugitive losses from valves, flanges, and other fittings). Because workers are in close proximity to leak sources, they can be exposed to much higher chemical concentrations than the community. Dispersion models indicate that near-field (worker) exposures can be several orders of magnitude higher than community exposures (Benarie, 1980). Specific job tasks may also produce brief releases of gases or other chemicals. These can occur during gas sample extraction for analysis, during daily pressure readings at each well, and during ongoing inspections of pipelines, compressors, storage tanks, scrubbers, and other equipment. In addition to exposures to natural gas and contaminants from the storage wells, workers are also exposed to process materials that are stored on-site in above-ground storage tanks.

Potential for chemical exposures

As described previously, natural gas – predominantly methane – is injected and stored under pressure in underground depleted oil and gas reservoirs. Given that methane can act as a solvent while underground, the injected gas admixes with chemicals present in the storage reservoirs, and the composition of the contaminants likely varies between facilities given the geology and historical and sometimes still current oil and gas production activities (see Section 1.2). When gas is withdrawn from the storage reservoir it must be processed before it is re-introduced into the pipeline system. Processing includes cleaning to remove sand, dirt and other gases and non-methane VOCs using scrubbers, purifiers, or additional chemicals; adding methanol to prevent formation of hydrates; dehydrating the gas to remove water; and re-introducing odorants before the gas re-enters the pipeline (Personal Communication, McDonald Island UGS Facility Visit, 2017).

Thus, in addition to methane itself, several other chemicals used in on-site operations present possible hazards to workers. The origins of these chemicals are various, and include:

1. Natural contaminants from the underground storage reservoirs (e.g., benzene, toluene, xylenes, ammonia, acetaldehyde, hydrogen sulfide);

2. Formaldehyde, a known human carcinogen, formed predominantly at gas-fired compressors due primarily to combustion during normal operations;

3. Chemicals used to clean and treat the gas (e.g., glycols, methanol);

4. Odorants, typically mercaptans.

5. Possibly other chemicals used down-hole during routine well maintenance and other activities.

On-site materials we were able to identify during our site visit to McDonald Island include: mercaptans (odorants), triethylene glycol (for dehydration) and methanol (to prevent the formation of hydrates). Methanol is reported as emitted from UGS facilities in California (see Section 1.4.6). These compounds are typically stored in above-ground tanks, which have the potential both for fugitive emissions or larger uncontrolled leaks.

Hydrogen sulfide (H2S) presents both a toxic and a flammability hazard at the worksite after it is separated from the gas. Hydrogen sulfide is a flammable, colorless gas that is toxic at extremely low concentrations. Denser than air, hydrogen sulfide can accumulate in low-lying areas and smells like “rotten eggs.” The odor is easily recognizable and can cause anosmia, or loss of smell (OSHA, 2017a). At high concentrations, sense of smell can be lost immediately (olfactory paralysis) (OSHA, 2017b). High concentrations of hydrogen sulfide (above 500 ppm) can lead to unconsciousness, cessation of breathing, and death, while concentrations of 100-1000 ppm can adversely impact the respiratory, nervous, and cardiovascular systems (OSHA, 2017b).

Recommended exposure limits from the American Conference of Government Industrial Hygienists (ACGIH) and Agency for Toxic Substances and Disease Registry (ATSDR) are shown in Table 1.4-19. Note that in this section we use concentration units of ppm and ppb with the understanding that all concentrations are volumetric, often denoted ppmv or ppbv.

Table 1.4-19. Hydrogen sulfide and corresponding exposure limits as specified by the 1) ACGIH (2017) and 2) ATSDR (2017b).

Exposure period	Description	Limit
Short-term exposure limit (STEL) [1]	Short periods, 15-minutes	5 ppm
Threshold limit value (TLV) [1]	8-hour average	1 ppm
Time-weighted average (TWA) [1]	8-hour time-weighted average	1 ppm
Acute Minimum Risk Level (MRL) [2]	1 - 14 days	$<$ 70 ppb
Chronic Minimum Risk Level (MRL) [2]	15 - 364 days	$<$ 30 ppb

Removal of hydrogen sulfide, if present, is necessary to prevent corrosion of the pipelines and containment systems. Hydrogen sulfide can be removed by an absorbing agent such as diethanolamine (a possible human carcinogen) (IARC, 2000), by activated charcoal, or by high temperature catalytic hydrogenation followed by zinc oxide treatment. However, the removal process presents serious risk related to exposure to workers and is cited as a major concern by those responsible for worker health and safety. The extent of the hydrogen sulfide contamination likely varies considerably among the facilities, but where it is present several precautions are necessary. Because hydrogen sulfide is so toxic, direct-reading instruments are commonly used to measure hydrogen sulfide concentrations continuously in areas where it might be present, and workers wear continuous hydrogen sulfide monitors. Potential hydrogen sulfide exposures may occur from minor leaks encountered in maintenance and during manual sampling, which in refinery operations could result in concentrations above 300 ppm that are immediately hazardous to life or health (Burgess, 1995). While this information is reported for refinery operations, it may also be relevant when discussing UGS operations where hydrogen sulfide is present.

Despite requests to operators and regulators, we were unable to obtain any monitoring data from UGS facilities, although we understand that monitoring occurs where hydrogen sulfide is present in the gas. Notably, during the 2015 Aliso Canyon incident the concentration of hydrogen sulfide reached 185 ppb at a Porter Ranch community monitor (see Section 1.4.10), which is a remarkably high concentration given both toxicity and distance from the source. On-site concentrations must have been much higher and may have exceeded the short-term exposure level (STEL) and the threshold limit value (TLV) (Table 1.4-19).

Because of the toxic potency of hydrogen sulfide, instrumentation that can monitor hydrogen sulfide continuously and at the low concentrations should be installed where hydrogen sulfide may be present; furthermore, workers should wear instruments which can detect hydrogen sulfide below health-relevant concentrations and sound warnings when those concentrations are exceeded. We understand that hydrogen sulfide is a chemical of sufficient concern and UGS facilities should monitor it routinely when it is present in the gas; however, we were not able to obtain any of this monitoring data despite several requests.

Physical safety hazards: fires and explosions

On-site workers are especially at risk if an accidental release leads to fire and/or explosion. Such hazards are acknowledged by the requirements that each facility have an incident commander trained to the "first responder" operation level. During the 2015 Aliso Canyon UGS Facility SS-25 well LOC event, the incident commander was not sufficiently trained, and this failure led CalOSHA to cite SoCalGas for a serious violation (CalOSHA, 2017a; see Section 1.4.11.3). UGS facilities are also required to have an emergency plan that is well understood by all workers. OSHA requires preventing or minimizing the consequences of catastrophic releases of toxic, reactive, flammable, or explosive chemicals, which may result in toxic, fire, or explosion hazards (OSHA, 1992).

OSHA Process Safety Management of Highly Hazardous Chemicals standard contains requirements for the management of hazards associated with processes using highly hazardous chemicals and establishes a comprehensive management program that integrates technologies, procedures, and management practices (OSHA, 2017c). While these regulations articulate good practices, there is an exception to **process safety management (**PSM) for hydrocarbons used only as fuels, and so these regulations do not apply to UGS. We recommend that California should eliminate this exemption in the interest of occupational health risk reduction.

1.4.11.3 Occupational Aspects of the 2015 Aliso Canyon UGS Facility SS-25 LOC Event and Regulatory Oversight

There is a current legal dispute about which regulatory agency has jurisdiction over the health and safety of workers. The federal Occupational Safety and Health (OSH) Act covers most private sector employers and their workers. OSH also provides for states to develop their own programs that must be approved by OSHA. The California State Plan (approved by OSHA and administered through CalOSHA) covers all private sector places within the state with some exceptions; however, UGS facilities are not among the exemptions listed (OSHA, 2017d).

In June 2016, the California Division of Occupational Safety and Health (DOSH, or CalOSHA) cited SoCalGas concerning the 2015 Aliso Canyon SS-25 well LOC event for three serious and three general violations. The serious citations allege violations of:

- Petroleum Safety Orders (PSO) §6851 for allegedly failing to make "reasonable efforts" by inspection and maintenance to prevent the possible occurrence of leaks from piping consisting of casing and tubing of the wells;

- PSO §6845 for allegedly failing to ensure that well inspection complied with relevant American Petroleum Institute standards;

- General Industry Safety Orders §5192(q) for allegedly failing to make sure that the site incident commander was trained at the first-responder operations level and failure to certify that the commander knew how to implement the SoCalGas incident command system.

SoCalGas is challenging the legality of these citations and states that the "citation is preempted by the Federal Natural Gas Pipeline Safety Act" and that the Pipeline Safety Act (PSA) "expressly preempts all state and local safety standards for natural gas pipeline facilities and precludes state and local authorities from imposing or enforcing safety standards on natural gas pipelines except as permitted under federal law." These authorities, SoCalGas contends, must first obtain annual certification under the PSA, the firm asserts, and, it says, neither CalOSHA nor Los Angeles County have done so. "The only California authority certified to impose or enforce safety standards for SoCalGas natural gas pipelines and underground storage facilities is the California Public Utilities Commission," the complaint says (CalOSHA, 2017a; SoCalGas, 2017b).

Federal preemption claimed by SoCalGas may apply to safety of the pipelines, but not to the health and safety of workers. Similarly, it appears that CPUC is concerned with safety in the context of the integrity of the wells and pipelines and the quality of the gas, but not explicitly with worker health and safety (e.g., slips and falls, monitoring benzene exposure, etc.). Clearly safety as it relates to pipe and well hardware is important for worker safety, but there are other hazards workers face that do not directly compromise the natural gas supply. After searching the OSHA databases for inspection reports and chemical monitoring data, reading the CalOSHA inspector's notes and citations from the 2015 Aliso Canyon incident, reading the CalOSHA citations and the SoCalGas appeal of those citations and the lawsuit SoCalGas filed, and conducting or attempting to conduct interviews with CPUC, CalOSHA, SoCalGas and PG&E, we conclude it is unlikely that any regulatory agency is monitoring the health and safety of workers at California UGS facilities. Further, it is unlikely the companies are monitoring chemicals to which workers are exposed, except for hydrogen sulfide. Even the exception may prove this rule, as we were unable to obtain any reports of hydrogen sulfide exposures; it may well be that this chemical is monitored with an alarm to indicate life-threatening exposures, but that the values below this threshold are neither recorded nor reported.

1.4.11.4 Attempts to gather information about occupational health and safety risks

We contacted the following organizations in an attempt to obtain information about worker exposures to airborne contaminants and to fire and explosive hazards associated with UGS:

- National Institute for Occupational Safety and Health (NIOSH)

- NIOSH Western States Division

- Occupational Safety and Health Administration (OSHA)

- CalOSHA
- California Public Utilities Commission (CPUC)
- United Steel Workers Union, Health, Safety and Environment Office
- International Brotherhood of Electrical Workers (IBEW) 1245
- Current and past industrial hygienists at SoCalGas and PG&E
- Health and safety officers at McDonald Island facility

Most of the information that we were provided with came from the CalOSHA investigation, citations from the Aliso Canyon incident, the CPUC, conversations with an industrial hygienist who had worked at one of the major companies, and communications from a site visit to the McDonald Island UGS facility. The latter site visit provided some good insights about operations and staffing. We asked several questions related to occupational health and safety, but few of these were answered, and none of the data we requested (e.g., airborne measurements) were provided (see side bar above).

1.4.11.5 Occupational Health Summary

On-site workers are those most likely to be exposed to the highest concentrations of both routine and off-normal emissions, and dispersion models indicate worker exposures could be several orders of magnitude higher as compared to community exposures (Benarie, 1980). On-site workers are also most at risk from injury due to fire and explosion. As noted previously and in Section 1.5, most emissions likely originate from above-ground infrastructure, and hence the highest exposures will be experienced by those on-site, before significant dispersion mitigates the hazard. In Appendix 1.G, we provide a brief summary of some of the best practices that could be deployed to help to reduce occupational health risks. While well-intentioned agencies seek to mandate health and safety protections for all workers, employees and temporary workers associated with UGS activities may not be adequately protected and protective measures may not be effectively enforced.

1.4.12 Health and Safety Risks and Impacts of UGS in California: Findings, Conclusions, and Recommendations

In this section, we described and analyzed the human health and safety hazards, risks, and impacts of UGS facilities in California. The human health hazards and risks of underground gas storage (UGS) facilities depend on the following:

1. the composition of stored, withdrawn, and stripped and compressed gases
2. the reservoir type (e.g., dry gas vs. oil)

3. the age and mechanical integrity of the subsurface and surface infrastructure

4. the type and number of gas compressors

5. the long-term expected emissions rate of chemical constituents from the wells

6. the magnitude and duration of emissions during containment failures

7. atmospheric dispersion conditions during the period of release

8. the number and density of gas storage, oil and gas production, and other wells in the vicinity of a loss of zonal isolation in the subsurface collection of UGS infrastructure

9. the activities and locations of on-site workers and contractors

10. the location and density of downwind populations

11. the location of sensitive populations as reflected by the very young, the elderly, women of childbearing age, schools, child care facilities, hospitals, and elderly care facilities

12. the prevalence of groundwater aquifers proximal to UGS facilities

Effective risk management requires that information on each of these 12 categories is available to regulators, decision-makers, site managers, and local emergency managers, so that decisions can be well informed. Risk management plans for addressing public health should include a process that provides site managers and first responders with the following information:

- A list of the chemical composition of the downhole stored gas (down to the parts per billion concentration), withdrawn gas (immediately after withdrawal), and stripped gas delivered into the pipeline. This information should contain toxicological information on each chemical constituent.

- A comprehensive list of chemicals stored on site, e.g., odorants and glycols including information on their mass and use.

- Tools for continuous air-quality monitoring.

- On-site weather stations to provide real-time information on the likely direction and concentration of off-site emission transport.

- Access to real-time air dispersion modeling tools.

- Geospatial locations of residents, workers, and sensitive populations.
- Communications channels with local first-responders.

Below, we provide the major findings, conclusions, and recommendations from our assessment of the human health dimensions of UGS facilities in California.

1.4.12.1 Emissions Inventory Information Gaps and Uncertainty

Finding: There are a number of human health hazards associated with UGS in California that can be predominantly attributable to exposure to toxic air pollutants. These toxic compounds emitted during routine and off-normal emissions scenarios include but are not limited to odorants, compressor combustion emissions, benzene, toluene, and other potentially toxic chemicals extracted from residual oil in depleted oil reservoirs. Given the limited number of compounds monitored for during the 2015 Aliso Canyon incident compared to the number of compounds reported to the California Air Resources Board as emitted from UGS facilities, there is significant uncertainty as to the human health risks and impacts of this large LOC event both over the short- and long-term. Our repeated attempts to acquire useful information about gas composition at each UGS facility in California were unsuccessful. Working with the CPUC, we made formal requests to all operators seeking information on the chemical composition of the stored gas. All responded, but none could provide the detailed information we needed (See Appendix 1.D).

Conclusion: Because emissions inventories for UGS facilities lack temporal, spatial, and technology-specific detail as well as verifiability of emission types and rates, currently available emissions inventories cannot support quantitative human exposure or health risk assessments. There is a need to identify the chemical composition of the gas that is stored, withdrawn, stripped, and delivered to the pipeline, so that associated hazards during routine and off-normal emission scenarios can be assessed. (See Conclusion 1.5 in the Summary Report.)

Recommendation: Agencies with jurisdiction should require that UGS facility operators provide detailed gas composition information at appropriate time intervals. Additionally, these agencies should require the development of a comprehensive chemical inventory of all chemicals stored and used on-site, and the chemical composition of stored, withdrawn, stripped and compressed gas for each UGS facility. These data should be used to prioritize chemicals to enable site operators and local first responders to set health-based goals for monitoring and risk assessment actions. (See Recommendation 1.5 in the Summary Report.)

1.4.12.2 Health Symptoms in Communities Near the 2015 Aliso Canyon Incident Were Attributable to the Aliso Canyon UGS Facility

Finding: The majority of households near the Aliso Canyon UGS facility experienced health symptoms during the SS-25 blowout and after the well was sealed, and these symptoms were likely related to the gas leak and/or other emission sources from the Aliso Canyon UGS facility. While many of the symptoms reported by residents match the symptom profile of exposure to mercaptans (gas odorants), other symptoms such as nosebleeds do not, suggesting that air pollutant and other environmental monitoring was not sufficiently inclusive of potential health-damaging pollutants.

Conclusion: Emissions from the 2015 Aliso Canyon incident were likely responsible for widespread health symptoms in the nearby Porter Ranch population. These types of population health impacts should be expected from any large-scale natural gas releases from any UGS facility, especially those located near areas of high population density. However, many of the specific exposures that caused these symptoms remain uncertain due to incomplete information about the composition of the air pollutant emissions and their downwind concentrations. (See Conclusion 1.6a in the Summary Report.)

Recommendation: Community health risks should be a primary component of risk management plans and best management practices for emission reductions, and measures to avoid (normal and off-normal) gas releases should be immediately implemented at existing UGS facilities. In addition, options for public health surveillance should be considered both during and following major loss-of-containment events to identify adverse health effects in communities. (See Recommendation 1.6a in the Summary Report.)

1.4.12.3 Population Exposures to Toxic Air Pollutants Increase with Higher Emissions, Closer Community Proximity and Higher Population Density

Finding: Approximately 1.85 million residents live within five miles of UGS facilities in the State of California. In the absence of reliable information on emissions inventories and expected release rates, potential health hazards can be evaluated using normalized source-receptor relationships obtained from atmospheric transport models and best estimates of population distance and density. Both concentration/source and population-intake/source ratios (intake fraction) provide helpful tools to assess the variability of potential exposures and risks among different UGS facilities.

Conclusion: UGS facilities pose more elevated health risks when located in areas of high population density, such as the Los Angeles Basin, because of the larger numbers of people nearby that can be exposed to toxic air pollutants. Emissions from UGS facilities, especially during large loss-of-containment events, can present health hazards to nearby communities in California. Many of the compounds potentially emitted by underground gas storage facilities can damage health and place disproportionate risks on sensitive populations, including children, pregnant women, the elderly, and those with pre-existing respiratory and cardiovascular conditions. (See Conclusion 1.7 in the Summary Report.)

Recommendation: Regulators need to ensure that the risk management plans required as part of the new DOGGR regulations take into account the population density near and proximity to UGS facilities. One mitigating approach to reduce risks to nearby population centers could be to define minimum health-based and fire-safety-based surface setback distances between facilities and human populations, informed by available science and results from facility-specific risk assessment studies. This may be most feasible for future zoning decisions and new facility or community construction projects. Such setbacks would ensure that people located in and around various classes of buildings such as residences, schools, hospitals, and senior care facilities are located at a safe distance from UGS facilities during normal and off-normal emission events. (See Recommendation 1.7 in the Summary Report.)

1.4.12.4 Occupational Health and Safety Considerations

Finding: Based on toxic chemicals known to be present on-site, and publicly available emission reporting to air regulators under the Air Toxics Hot Spots Program, we have identified toxic chemicals used at and emitted from UGS facilities. These chemicals include, but are not limited to, hydrogen sulfide, benzene, acrolein, formaldehyde, and 1,3-butadiene. Currently we have found no available quantitative exposure measurements.

Conclusion: Workers at UGS facilities are likely exposed to toxic chemicals, but the actual extent of those exposures is not known. Without quantitative emission and exposure measurements, we cannot assess the impact of these exposures on workers' health. (See Conclusion 1.8 in the Summary Report.)

Recommendation: UGS facilities should make quantitative data on emissions of, and worker exposures to, toxic chemicals from UGS facility operations available to the public and to agencies of jurisdiction (e.g., CalOSHA, CPUC) to enable robust risk assessments. It may be advisable to require that UGS facilities be subject to the Process Safety Management of Highly Hazardous Chemicals Standard (29 CFR 1910.119), which contains requirements for the management of hazards associated with processes using highly hazardous chemicals. (See Recommendation 1.8a in the Summary Report.)

Recommendation: Require that UGS workplaces conform to requirements of CalOSHA and federal OSHA, and impose additional requirements to protect the health and safety of on-site workers (employees, temporary workers and contractors), whether or not they are legally bound to comply (SoCalGas, 2017b). These requirements include that (1) all training and preparation for incidents and releases be fully concordant with best practices (see Appendix 1.G); (2) all safety equipment be fully operational and up to date, readily available, and all workers trained in equipment location and proper use; (3) all incident commanders be provided with sufficient, current training; (4) all health and safety standards be observed for all workers on site; and (5) air sampling of workers' exposures be required during routine and off-normal operations to ensure that exposures are within the most health-protective occupational exposure limits. (See Recommendation 1.8b in the Summary Report.)

The exact chemicals to be monitored should be evaluated when more data are available about potential exposures, but some important ones include hydrogen sulfide where it is present, benzene, formaldehyde, the odorants in use at the facility (e.g., mercaptans), methanol, triethylene glycol, and other dehydrants.

1.4.12.5 Continuous Facility Air-Quality Monitoring

Finding: Many UGS facilities emit multiple health-damaging air pollutants during routine operations. Available emissions inventories suggest that the most commonly emitted air pollutants associated with UGS by mass include nitrogen oxides, carbon monoxide, particulate matter, ammonia, and formaldehyde. For instance, Aliso Canyon is the single largest emitter of formaldehyde in the South Coast Air Quality Management District. Gas-powered (as compared to electric-powered) compressor stations are associated with the highest continuous emissions of formaldehyde. CARB regulations (CARB, 2017c) for underground gas storage facilities in place since October 1, 2017 require continuous methane concentration monitoring at facility upwind and downwind locations (at least one pair of upwind and downwind locations) but without air sampling.

Conclusion: There is a need to track, and, if necessary, reduce emissions of toxic air pollutants from UGS facilities during routine operations. (See Conclusion 1.9 in the Summary Report.)

Recommendation: Agencies with jurisdiction should require actions to reduce exposure of on-site workers and nearby populations to toxic air pollutants, other health-damaging air pollutants emitted from UGS facilities during routine operations, and ground level ozone, nitrogen oxides, and other ozone precursors. These steps could include (1) the implementation of air monitors within the facilities and at the fence line or other appropriate locations—preferably with continuous methane monitoring with trigger sampling to quickly deploy appropriate off-site air quality monitoring networks during incidents; (2) the increased application and enforcement of emission control technologies to limit air pollutant emissions; (3) the replacement of gas-powered compressors with electric-powered compressors to decrease emissions of formaldehyde; and (4) the implementation of health protective minimum-surface setbacks between UGS facilities and human populations. (See Recommendation 1.9 in the Summary Report.)

1.4.12.6 Community Symptom-based Environmental Monitoring for High Priority Chemicals

Finding: Symptom reporting and environmental monitoring in Porter Ranch, CA, during and after the 2015 Aliso Canyon incident indicate that chemicals and materials sourced from the SS-25 well entered residences, demonstrating clear indoor and outdoor exposure pathways. However, air pollutant exposures during the SS-25 event are significantly uncertain with respect to characterizing health-relevant exposures, because (1) detection limits for air pollutants such as benzene, mercaptans, and other toxic air pollutants during the SS-25 blowout were often above health and/or odor thresholds; (2) air and other environmental monitoring during much of the time of the SS-25 blowout was non-continuous; and (3) only a small fraction of pollutants known to be associated with UGS facilities was included in the monitoring.

Many of the health symptoms most commonly reported by residents of Porter Ranch, CA, during and after the SS-25 blowout are consistent with exposures to mercaptans. However, reporting of epistaxis (bloody noses) suggests that there could have been exposures to hydrogen sulfide, hexane, or other substances from the Aliso Canyon UGS facility that were not monitored for during and after the blowout. Environmental and air sampling inside Porter Ranch homes during and following the SS-25 blowout indicate that chemical constituents and other materials sourced from the Aliso Canyon UGS facility entered residences, demonstrating clear indoor and outdoor exposure pathways. Monitoring during and after the SS-25 blowout was limited by detection limits above health-relevant and/or odor thresholds and non-continuous sampling. Health risk management requires quick and coordinated deployment of indoor and outdoor environmental sampling for high priority chemicals, using health-relevant limits of detection.

Conclusion: Effective health risk management requires continuous, rapid, reliable, and sensitive (low-detection limit) environmental monitoring of chemicals of concern in both ambient and indoor environments. (See Conclusion 1.6b in the Summary Report.)

Recommendation: To support a more detailed exposure assessment to communities located near UGS facilities, procedures need to be in place to be able to: (1) rapidly deploy a network of continuous, reliable, and sensitive indoor and outdoor sensors for high priority chemicals, capable of detecting emissions at levels below thresholds for minimum risk levels; and (2) employ real-time atmospheric dispersion modeling to provide information about the dispersion and fate of a large release of stored natural gas to the environment. (See Recommendation 1.6b in the Summary Report.)

1.4.12.7 Chemical Disclosure for Storage Wells and Associated Aboveground Operations

Finding: While chemicals used in oil and gas production during routine activities (e.g., drilling, routine maintenance, completions, well cleanouts) and well stimulation (e.g., hydraulic fracturing and acid stimulation) are reported for all other wells in the South Coast Air Quality Management District (SCAQMD rule 1148.2; Stringfellow et al., 2017), no such disclosures are made for UGS wells. And this is true for UGS facilities statewide. UGS operators disclose chemical information to the California Environmental Reporting System (CERS) for chemicals stored on-site; however, this information is not publicly available for all facilities, does not include what the chemicals are used for, or the mass or frequency of use on-site, and often lists product names without unique chemical identifiers (SoCalGas, 2015). As such, it is likely that on-site chemical use occurs, but the composition of those chemicals, the purpose, mass, and frequency of their use, and their associated human health risks during normal and off-normal events at UGS facilities, remain unknown.

Conclusion: To be able to conduct comprehensive hazard and risk assessment of UGS facilities, risk managers, regulators, and researchers need access to detailed information for all chemicals used in storage wells and in associated infrastructure and operations. (See Conclusion 1.22 in the Summary Report.)

Recommendation: Require operators to disclose information on all chemicals used during both normal operations and off-normal events. Each chemical used downhole and on UGS facilities should be publicly disclosed, along with the unique Chemical Abstract Service Registry Number (CASRN), the mass, the purpose and the location of use. Studies of the community and occupational health risks associated with this chemical use during normal and off-normal events should be undertaken. (See Recommendation 1.22 in the Summary Report.)

1.4.12.8 Explosion and Flammability Considerations

Finding: During large LOC events, downwind methane concentrations can be higher than flammability or explosion limits. This poses a significant threat to people and property due to sustained fires and collapse of buildings and infrastructure from explosions. For risk assessment purposes, this study compared predicted concentrations from atmospheric dispersion models with methane concentration flammability limits. There are air dispersion conditions and failure scenarios that can present risks of severe harm to workers and nearby communities if a release of flammable gas is ignited due to exposure to high temperatures and associated radiation from a blast. Based on our modeling, the methane concentrations in the close vicinity of the leakage points may exceed the lower flammability limits for typical "off-normal" leakage fluxes. Flammable zones are typically not expected to extend beyond UGS facility boundaries, unless the leak rates are extremely large, i.e., larger than the fluxes experienced in the 2015 Aliso Canyon incident.

Conclusion: Each UGS facility needs an assessment of emitted natural gas combustion potential, and a mapping of the flame and the thermal dispersion associated with this combustion. (See Conclusion 1.10 in the Summary Report.)

Recommendation: Regulators and decision-makers should require the implementation and enforcement of best practices to reduce the likelihood of ignition of flammable gases in and near UGS facilities. Occupational and community hazard zones should be delineated for each UGS facility (possibly based on bounding simulations conducted with atmospheric dispersion models) to focus risk mitigation on elimination of leakage and ignition sources (loss prevention) and safer site-use planning. (See Recommendation 1.10 in the Summary Report.)

1.5 ATMOSPHERIC MONITORING FOR QUANTIFICATION OF GHG EMISSIONS AND UGS INTEGRITY ASSESSMENT IN CALIFORNIA

1.5.1 Abstract

At the time of the Aliso Canyon incident in 2015, there was no reported quantitative operational monitoring program for ambient methane or other trace gases at Aliso Canyon (or any other UGS facility in California). A variety of methane measurement methods was deployed in the months that followed to improve confidence in the SS-25 well leak rate as it evolved in response to efforts to control the well and reduce reservoir pressure by gas withdrawal. These methods include complementary airborne surveys using low-altitude *in situ* sampling and high-altitude remote sensing, as follows: (1) total methane emissions were determined using an aircraft equipped with a Picarro *in situ* methane analyzer flying cylindrical patterns around the facility; and (2) spatially resolved emissions from individual infrastructure components were estimated using an aircraft equipped with JPL's Airborne Visible/Infrared Imaging Spectrometer (AVIRIS-NG). Both airborne methods have since been applied to other UGS facilities in California: Total facility methane emissions were measured at selected facilities roughly 40 times, from June 2014 through August 2017. Local methane emissions were measured roughly 80 times from January 2016 through August 2017 with the AVIRIS-NG method. UGS facilities are also subjected to daily surveys of all wellheads with hand-held gas analyzers, offering the ability to find small concentration anomalies at wellheads. Together, these measurements provide relevant information on current UGS facility emissions, discussed below in the context of greenhouse gas (GHG) emissions as well with regards to integrity implications.

In general, methane (CH_4) emissions from UGS facilities are a potential concern for climate change because methane is a powerful GHG. Methane emissions from the total California natural gas supply chain from production to combustion should be carefully controlled below ~3% of the total amount used if short-term (~20 yr) climate impacts are to be minimized. We compared the recent airborne measurements of methane emissions from gas storage facilities with annual GHG reporting by the UGS operators to the California Air Resources Board. Taken together, the mean emissions of roughly 1,060 kg/hr (~9.3 GgCH_4 (~0.5 Bcf annually) from the active UGS facilities in California are ~7.8% of total natural gas-related methane emission estimated by the California Air Resources Board (CARB) and ~2.6 times the CARB estimate for gas storage-related methane emissions. Those emissions are dominated by three facilities: Honor Rancho, Aliso Canyon (after the SS-25 leak repair), and McDonald Island, which contribute 45%, 16% and 14%, respectively, to the UGS total. We conclude that UGS-related methane emissions appear to be a small part of both California's methane and total GHG emission inventories. However, the ongoing methane emissions from California UGS facilities are roughly equivalent to having a 2015 Aliso Canyon incident every 10 years. This, combined with super-emitter (defined as anomalous emissions relative to expectation) activity at three facilities, suggests a mitigation opportunity for meeting the state's short-lived climate pollutant mitigation targets in the natural gas sector.

Measurements of natural gas emissions at UGS facilities also provide an atmospheric tracer that can enable efforts to monitor the integrity of surface and subsurface infrastructure—potentially offering early warning to minimize the impact of leaks and avoid LOC and other hazardous situations for some failure modes. Methane in particular is both the primary constituent of natural gas and can be measured by a variety of methods to identify, diagnose, and guide responses to integrity issues. Methane emissions are also qualitatively indicative of emissions of toxic compounds (e.g., benzene), though relationships vary with reservoir. There are many methane measurement methods that can be applied to UGS leak detection; however, they have differing capabilities and limitations. Several of these methods have been successfully demonstrated in operational field conditions at Aliso Canyon, Honor Rancho, and other facilities, including several examples that illustrate the potential for coordinated application of multiple synergistic observing system "tiers."

1.5.2 Quantification of Greenhouse Gas Emissions

This section reviews current knowledge on methane (CH_4) emissions from underground gas storage (UGS) facilities in California. The context for concern about methane emissions in this section is climate change owing to the fact that methane is the second largest anthropogenic greenhouse gas (GHG) emitted after carbon dioxide (CARB, 2017b; 2017d). The following four sections present results and discussion of (1) historical natural gas usage in California, (2) direct measurements of GHG emissions from UGS operations, (3) identification of significant knowledge gaps on emissions, (4) the comparison of average UGS operational emissions with the 2015-2016 Aliso Canyon blowout, and (5) the comparison of average ongoing emissions plus the Aliso Canyon blowout emissions, with California's total GHG emissions and those emissions not included under current cap and trade legislation.

1.5.2.1 Background: GHG Emissions from the Natural Gas Sector

Total monthly natural gas use and stored gas expressed in mass units are show in Figure 1.5-1. As shown, both seasonal variations and longer term trends indicate that while gas usage has been relatively constant, gas storage has increased roughly 10% between 2001 to 2017 (U.S. EIA, 2017).

From the GHG perspective, total natural-gas-related emissions can be summarized by noting that the vast majority of natural gas is combusted during power production, resulting in CO_2 emissions. However, methane is both the dominant component of natural gas (typically ~ 90-95% by volume) and a strong GHG itself, with a mass weighted global warming potential (GWP) of 33 and 86 times that of CO_2 for 100- and 20-year time scales, respectively, on a mass basis in the 5th Intergovernmental Panel on Climate Change (IPCC) assessment, if carbon feedbacks are included (Myhre et al., 2013). Hence, the importance of methane can be put in a climate perspective relative to total CO_2 emissions by equating the radiative forcing of the CO_2 emitted with that from emitted CH_4. Accounting for the difference in molecular weights, and assuming natural gas is essentially pure CH_4, fractional

emissions of CH_4 at 3.2% and 9%, for 20-yr and 100-yr time scales, respectively, double the total radiative forcing arising from CO_2 alone (Fischer et al., 2017). This suggests that CH_4 emissions from the natural gas supply chain from production to combustion should be carefully controlled below ~3% if short-term climate impacts are
to be minimized, a result similar to that identified in previous work (Alvarez et al., 2012).

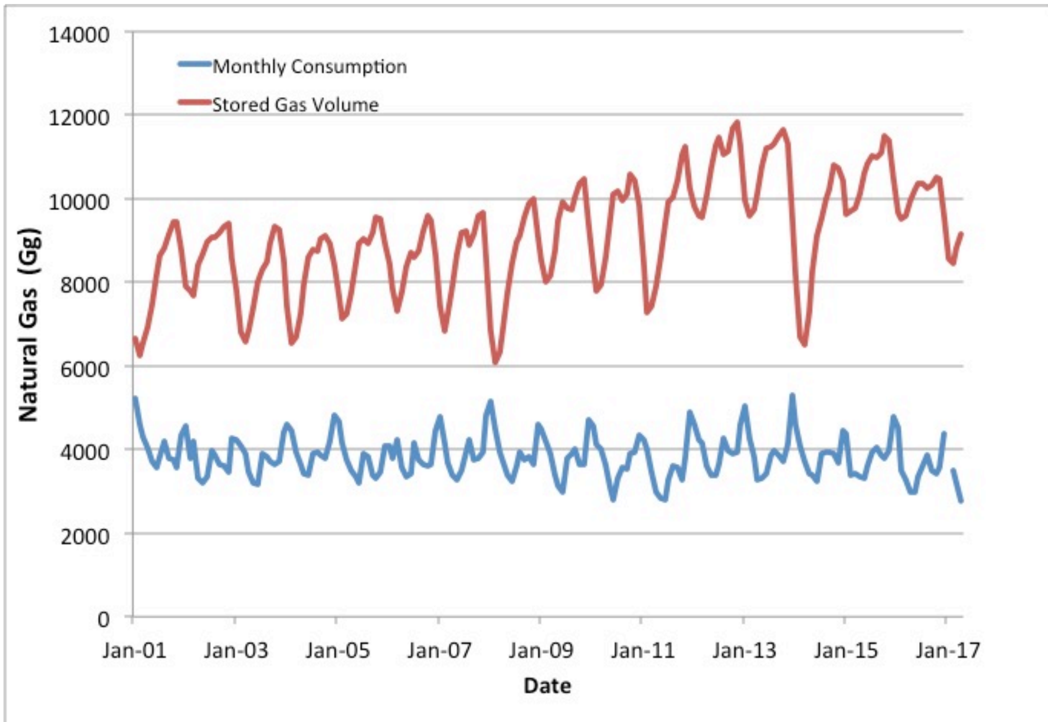


Figure 1.5-1. Total monthly natural gas use and stored gas in California for 2001-2017. Seasonal cycles in both gas usage and stored gas are observed together with interannual variations. Note assuming natural gas is pure methane (CH_4), 1 Bcf = 19 Gg.

1.5.2.2 Estimates of Average Ongoing Emissions for California Natural Gas Storage Facilities

1.5.2.2.1 Methods

Here we describe two aircraft-based methods and results for estimating average methane emissions from California UGS facilities derived from both *in situ* and remotely sensed CH_4 mixing ratio measurements combined with wind measurements. Together, the two airborne systems conducted repeated surveys of the 12 active UGS facilities in the state between June 2014 and August 2017. Nine of the facilities were surveyed between 3 and 9 times, and the three top-emitting facilities—Honor Rancho, McDonald Island, and Aliso Canyon—were surveyed 25, 30, and 13 times, respectively[7].

Airborne in situ methane imaging and mass-balance emission estimates

To quantify facility emissions with *in situ* measurements of methane and wind velocities, cylindrical flight patterns ranging in elevation from ~150 ft (45 m) to 5,000 ft (1.5 km) above ground were employed to provide data to calculate facility emissions as approximated by the divergence of mass flux within the flight cylinder. An example flight pattern and the resulting methane anomalies are shown in Figure 1.5-2.

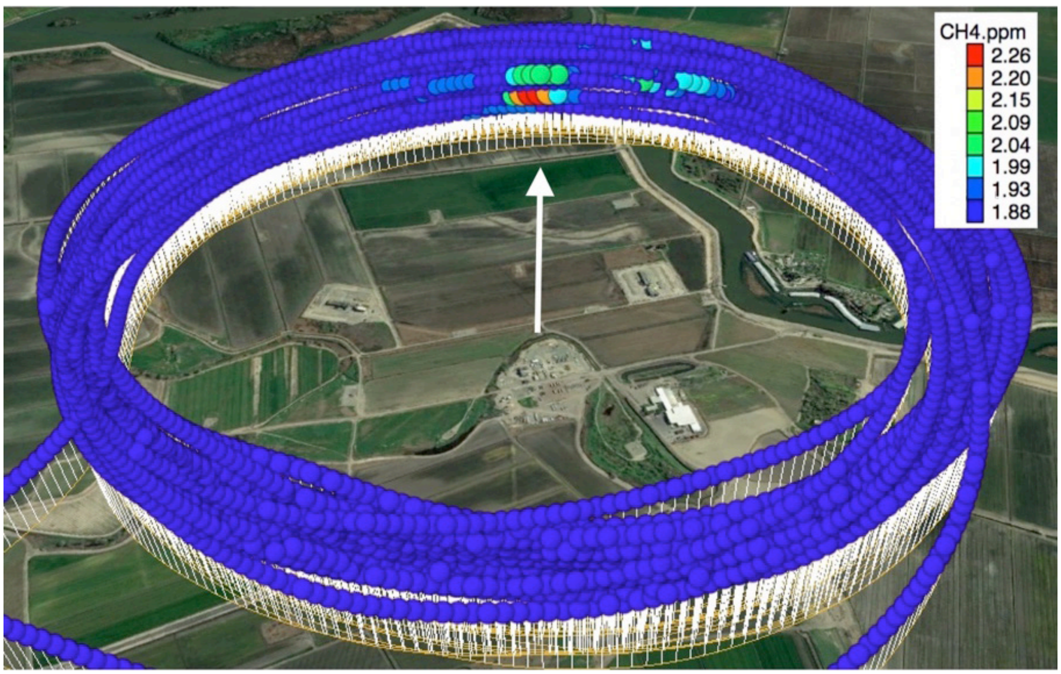


Figure 1.5-2. Methane mixing ratios observed from an airplane flying multiple loops above the McDonald Island gas storage facility on May 13, 2015. The white arrow in the center of the figure shows the mean wind direction measured by the aircraft, with the on-site compressor facility located at the base of the arrow. Methane enhancements are clearly visible on the downwind side of the loop as compared with nearby background values (~1.9 ppb) obtained in the remainder of the loop. Note, the thin white lines indicate the height of each data point above the ground surface, in this flight ranging from 320 to 1,340 ft (98 to 406 m) above ground level.

7. Note that the 2015 Aliso Canyon incident was not resolved until the bottom-kill on February 11, 2016, and the soil outgassing likely did not reach an e-folding level until early March 2016. The Aliso Canyon methane emission estimates (and number of surveys) cited in this section exclude data collected prior to March 2016.

Using Gauss' Theorem, Conley et al. (2017) estimate emissions from a site, E, as:

$$E = \int_{z_{min}}^{z_{max}} \oint c' \boldsymbol{u_h} \bullet \hat{\boldsymbol{n}} \, dl \, dz$$

(1)

where the outer integral represents the vertical extent of the cylindrical flight pattern, which extends from the lowest safe altitude, z_{min}, to the maximum flight altitude, z_{max}, where there is no indication of a plume crossing, and is the vector normal to the flight path. Here, the horizontal advective methane flux, $c'u_h$, is computed as the product of methane density variation, c', after subtracting the mean density for each loop, multiplied by u_h, the horizontal wind vector. In order to average over natural turbulent variability, the measurements are first averaged into altitude bins of ~100 m depth. The bottom altitude bin is extrapolated to the ground assuming constant concentration and winds, which was shown to be accurate to within 10-20% of estimated emissions during controlled release testing at a range of distances downwind of the source (Conley et al., 2017).

Applying the mass-balance method described above, Mehrotra et al., (2017) report methane emissions from a subset of ten gas storage facilities and nine compressor stations in California. The authors also provide an analysis of uncertainty that includes consideration of the number of loops flown, the stability of the wind velocities, and the fraction of the plume estimated below the lowest flight altitude from the controlled release experiments from Conley et al. (2017). This analysis suggests that uncertainties for the storage facility flights likely range from 10% to 30% of estimated emissions.

Airborne infrared imaging spectroscopy and mass-balance emission estimates

The next generation Airborne Visible/Infrared Imaging Spectrometer (AVIRIS-NG) measures ground-reflected solar radiation from the visible to infrared spectral regions (350 to 2,500 nm). AVIRIS-NG provides the ability to image localized atmospheric plumes of CH_4, geolocate their emission sources, quantify their enhancements relative to background CH_4 mixing ratios, and estimate emission fluxes when combined with wind measurements (Thorpe et al., 2016). This push broom instrument has a 34° field of view and operates from aircraft, allowing for efficient mapping of large regions. Increasing flight altitude affects the ground resolution (i.e., the size of each image pixel increases) while the image swath increases. For surveys of California UGS facilities in 2016, AVIRIS-NG flew at 3 km (9,800 ft) above ground level, resulting in 3 m image pixels and a 1.8 km swath width.

AVIRIS-NG retrieval of column-averaged mixing ratios for CH_4 point source plumes is based on absorption spectroscopy (Figure 1.5-3) and has been used for a number of prior CH_4 studies, including the COMEX investigation observing Kern River, CA oil fields (Thompson et al., 2015), a campaign to Four Corners, CO and NM (Frankenberg et al., 2016), Aliso

Canyon, CA, (Thompson et al., 2016), and a study of California landfills (Krautwurst et al., 2017). Controlled-release experiments have demonstrated robust detection of CH_4 plumes for emission rates as low as 10 kg/hr for a range of altitudes and wind speeds (Thorpe et al., 2016).

For each plume, an Integrated Methane Enhancement (IME) in units of $kgCH_4$ is calculated by integrating over the physical area of the plume. This is done by first calculating the mass of CH_4 present in each image pixel as follows:

$$kg = \frac{ppm*m}{1} * \frac{1}{1E6\,ppm} * \frac{pixel\,res.\ (m)*pixel\,res.\ (m)}{1} \frac{pixel\,res.\ (m)*pixel\,res.\ (m)}{1} * \frac{1000\,L}{1\,m3} * \frac{1\,mole}{22.4\,L} * \frac{0.01604\,kg}{1\,mole}$$

(2)

The IME is then calculated by integrating over all pixels exceeding a specified threshold in a given plume.

The IME and plume length can then be combined with wind speed information to estimate point source emission rates as follows:

$$\text{Emission rate (kg/hr)} = \frac{IME\ (kg)}{1} * \frac{Wind\,speed\ (m)}{s} \frac{IME\ (kg)}{1} \frac{Wind\,speed\ (m)}{s} * \frac{1}{plume\,length\ (m)} * \frac{3600\,s}{1\,hr}$$

(3)

Wind-speed errors represent one of the largest sources of uncertainty in estimating emission rates with this method. For this reason, Large Eddy Simulation (LES) and Gaussian plume modeling is typically used to validate surface wind measurements for many of the UGS facilities studied here.

An example of AVIRIS-NG detection of CH_4 plumes at McDonald Island is provided in Figure 1.5-4.

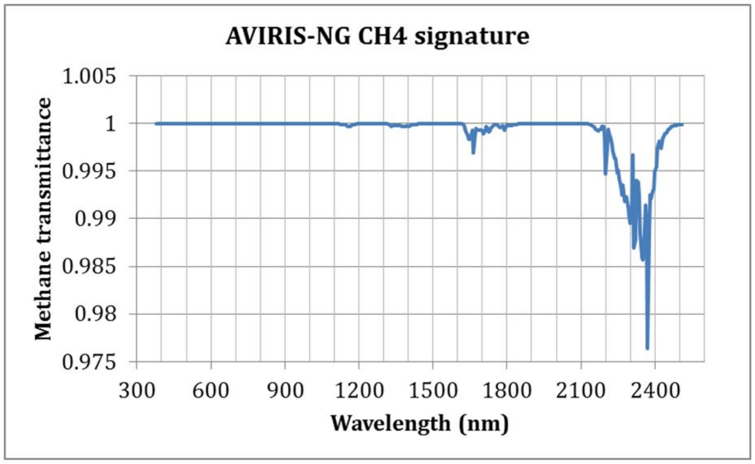


Figure 1.5-3. CH_4 absorption signature (transmittance) plotted for the wavelength range measured by AVIRIS-NG. Strong absorptions are present between 2,200 and 2450 nm.

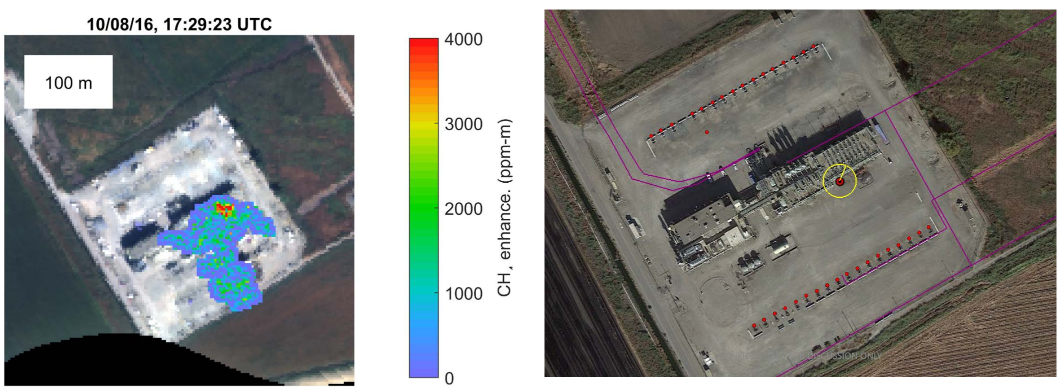


Figure 1.5-4. Example of AVIRIS-NG detection of a CH_4 plume and quantification of column mixing ratios at the McDonald Island Turner Cut gas injection and recovery control station (left-hand panel). Approximate location of strongest leak location marked with yellow circle together with gas wells shown as two lines of red dots on visible image taken during the AVIRIS-NG observations (right-hand side panel).

1.5.2.2.2 Industry Reporting to California Air Resources Board

Measurements of methane emissions from gas storage facilities can be compared with annual GHG reporting from industry to the California Air Resources Board (CARB reporting, 2017a; 2017b). In some cases, facilities are co-located with or near other methane-emitting activities (e.g., livestock, petroleum production) requiring care in interpreting the estimated UGS-related emissions.

1.5.2.2.3 Results of Airborne Measurements of California Storage Facilities

Table 1.5-1 summarizes observations of methane emissions over the period June 2014 through August 2017 for the 12 active California natural gas storage facilities. With the exceptions of Aliso Canyon, McDonald Island, and Honor Rancho, all of the other sites were found to emit less than 100 kg/hr (<1 Gg CH_4/yr (<0.05 Bcf/yr)) on average and together constitute less than 25% of total storage-related GHG emissions. The spatial locations of methane emissions for the larger emitters were identified with the infrared imaging method, and emission modes are listed in Table 1.5-1. During the McDonald Island measurements, PG&E recognized the need for maintenance and began inspection and repairs of wells in the summer of 2016.

Taken together, the mean emissions of roughly 1,060 kg/hr (~9.3 GgCH_4 ~0.5 Bcf annually) from the active UGS facilities in California are ~7.8% of total natural-gas-related methane emission estimated by the California Air Resources Board (CARB) and ~2.6 times the CARB estimate for gas storage-related methane emissions (CPUC, 2016).

Additionally, eight UGS facilities participated in California's GHG Reporting Program in 2015. Comparison of reported and measured emissions from those facilities indicates wide disagreement, with three significant underestimates and three overestimates. This, combined with the fact that four facilities did not report data, suggests room for improvement in UGS methane accounting.

1.5.2.2.4 Uncertainties and Recommended Measurement Improvements

The focused application of the airborne methane measurement systems described here was unprecedented before the 2015 Aliso Canyon incident. Hence, there are no historical, independent measurement data available for assessing methane emissions from California UGS prior to 2015. Arguably, UGS methane emissions in California in the immediate wake of the Aliso Canyon incident are not entirely representative of long-term emissions from this sector. Additionally, the combination of the intermittent measurements reported here and the observed episodic signatures of UGS methane emissions prevent an unambiguous comparison with annual averages. To reduce the possibility of overestimating emissions, the instantaneous measurements described here were scaled by the observed frequency of methane sources at each facility, typically reducing the mean emission rate. However, intermittent sampling remains a source of uncertainty in estimates of annual mean emissions. We therefore recommend that a more frequent and robust methane measurement program be established for UGS facilities, perhaps combining persistent fence-line monitoring by UGS operators (capable of basic event detection through threshold detection methods), frequent semi-quantitative on-site inspections for leakage detections as required by the California Air Resources Board (CARB, oil and gas regulation, 2017c)[8],

8. The CARB regulations (CARB, 2017c) specify measurement of gas concentration rather than flow rate as a protocol for detection of leakage, rather than quantification of leakage of emissions.

and independent, periodic quantitative airborne measurements that would provide a more accurate estimate of annual average emissions and reduce the likelihood of leaks due to equipment malfunction or damage not being rapidly detected and repaired.

Table 1.5-1. Summary of annual methane emissions for California gas storage facilities from a combination of airborne surveys using in-situ measurements and remote sensing from June 2014 through August 2017.

Facility	Observed emission modes	# obs	source detection frequency	Mean Measured CH4 Emissions, 2016 (kg/hr)	% of measured emissions	Reported CH4 emissions[1], 2015 (kg/hr)	% of California CH4 inventory for NG sector[2], 2015	% of California inventory for UGS[3], 2015
Aliso Canyon (after blow-out incident)[4]	residual soil outgassing from earlier well blowout; compressor loss	13	0.73	166	16%	152	1.2%	40%
McDonald Island	maintenance and leading bypass valves	30	0.86	150	14%	n/r	1.1%	36%
Wild Goose	episodic compressor loss	4	0.47	35	3%	88	0.3%	8%
Honor Rancho	persistent leaking bypass valve; episodic compressor loss; blowdown event	25	1.00	482	45%	76	3.5%	116%
Gill Ranch	episodic compressor loss	9	0.77	88	8%	242	0.6%	21%
La Goleta	unknown	5	0.17	36	3%	86	0.3%	9%
Los Medanos	unknown	6	0.11	11	1%	3	0.1%	3%
Lodi	none	5	0.24	0	0%	1	0.0%	0%
Kirby	unknown	6	0.22	37	3%	6	0.3%	9%
Princeton	unknown	5	0.43	43	4%	n/r	0.3%	10%

1 Aliso Canyon observations included here cover the period after the SS-25 leak was plugged and soil out-gassing e-folding limit was reached (early March, 2016). Also note that with the exception of the first two weeks of August 2017, Aliso Canyon was in an idle state during this period.

2 CARB GHG reporting program 2015.

3 CPUC, 2016.

4 CPUC, 2016

Facility	Observed emission modes	# obs	source detection frequency	Mean Measured CH4 Emissions, 2016 (kg/hr)	% of measured emissions	Reported CH4 emissions[1], 2015 (kg/hr)	% of California CH4 inventory for NG sector[2], 2015	% of California inventory for UGS[3], 2015
Playa Del Rey	none	3	0.00	0	0%	n/r	0.0%	0%
Pleasant Creek	unknown	6	0.33	16	2%	n/r	0.1%	4%
totals		117		1064		654	7.8%	256%

1 Aliso Canyon observations included here cover the period after the SS-25 leak was plugged and soil out-gassing e-folding limit was reached (early March, 2016). Also note that with the exception of the first two weeks of August 2017, Aliso Canyon was in an idle state during this period.

2 CARB GHG reporting program 2015.

3 CPUC, 2016.

4 CPUC, 2016

1.5.2.3 Summary of Methane Emissions from the 2015 Aliso Canyon Incident as an Example of a Large Leakage Event

The large 2015 Aliso Canyon incident methane emissions during the 2015-2016 SS-25 well blowout (~100 Gg CH_4) reported by Conley et al. (2016) are roughly equivalent to ~10 years of the average emissions measured for California's remaining storage facilities. It is also worth noting that measurements at Aliso Canyon following the SS-25 well repair were found to be similar to that from the two other high-emitting UGS facilities (Honor Rancho and McDonald Island), suggesting that some aboveground leaks remain present at Aliso Canyon despite the reservoir being partially depressurized. This suggests the need for careful monitoring following resumption of operations at Aliso Canyon, and especially if Aliso Canyon is operated again at full pressure.

1.5.2.4 Comparison of Average Ongoing Emissions with California's Natural Gas Methane, Total Methane, and Total GHG Emissions

As noted above, the observations to date suggest UGS-related methane emissions are approximately 8% of the current total natural gas-related methane emissions, which are 2.9% of total gas use (CPUC, 2016). Comparing this with total California methane, the storage emission estimate of ~10 Gg CH_4/yr is still only ~0.5% total California CH_4 emissions (~ 2Tg CH_4 /yr), and ~0.05% of total GHG emissions (w/ 100 yr GWP = 25 gCO_2eq/gCH_4) estimated by CARB (GHG Inventory, 2017a). We conclude that UGS-related methane emissions appear to be a small part of both California's methane and total GHG emission inventories. If both methane and total GHG emissions are reduced by 40% to 80% as required by 2030 and 2050, respectively, then storage-related methane emissions will become proportionately more important unless controlled. We also note that the 2015 Aliso Canyon leak would correspond to roughly 1/3 of total petroleum and natural gas-related methane, 5% of total methane, and ~0.5% of total California GHG emissions. Hence, we recommend that care should be taken to reduce the frequency and magnitude of episodic emissions observed at Honor Rancho, McDonald Island, and Aliso Canyon, whatever their cause may be, through improved leak detection and equipment repair/replacement programs (including but not limited to those required by the CARB regulations (CARB, 2017c)), as well as additional controls aimed at preventing another major leak of the magnitude that occurred at Aliso Canyon.

1.5.2.5 Recommendations from GHG Emission Measurement and Analysis

Finding: Observed methane emissions vary by factors >10× across sites, with three sites (Honor Rancho, McDonald Island, and Aliso Canyon) dominating emissions. Within sites, variations of ~3-5× occur over time. Directly observed emissions are 2-5× higher than the average of emissions reported to CARB. Observations suggest total California UGS emissions are ~9.3 $GgCH_4$/yr (≈ 1% California total methane emissions) which is < 0.1% total California GHG emissions, with compressors and aboveground infrastructure apparently contributing the majority of the emissions.

Conclusion: Though there are discrepancies between directly observed greenhouse gas emissions and those reported to CARB, average methane emissions from UGS facilities are not currently a major concern from a climate perspective compared to other methane and GHG sources, such as dairies and municipal solid waste landfills. However, average methane emissions from UGS facilities are roughly equivalent to an Aliso Canyon incident every 10 years, and hence worthy of mitigation. (See Conclusion 1.11 in the Summary Report.)

Recommendation: An improved methane monitoring program is needed for better quantitative emissions characterization that allows for direct comparison with reported emissions. The monitoring program could benefit from a combination of persistent on-site measurements and higher accuracy, periodic independent surveys using airborne- and surface-based measurement systems. (See Recommendation 1.11a in the Summary Report.)

Recommendation: Average underground gas storage methane emissions should be monitored primarily for safety and reliability (see Recommendation 1.12 below), since the net GHG effect of UGS facilities is relatively small. However, most of the current GHG leakage detection measurements (e.g., of methane concentration) conducted at UGS facilities point to easily mitigatable sources for above-ground leaks, such as compressors or bypass valves. Thus, with regard to reducing GHG emissions, facilities should maintain and upgrade equipment (particularly compressors and bypass valves) over time, repair leaking equipment (e.g., following the new CARB regulations for natural gas facilities) (CARB, 2017c), and reduce leakage and releases (blowdowns) during maintenance operations. (See Recommendation 1.11b in the Summary Report)

1.5.3 Atmospheric Monitoring for Integrity Assessment

This section evaluates the potential contribution of atmospheric monitoring to end-to-end assessments of the physical integrity of UGS facilities and associated risk management.

This evaluation builds on previous discussions regarding the impact of loss-of-containment incidents on air toxics (Section 1.4) and greenhouse gases (Section 1.5.2).

1.5.3.1 Background

In Section 1.6.5.3 we review regulatory changes being developed in California that focus on assuring the ongoing physical integrity of UGS operations, including new requirements on testing, monitoring, and inspections. That review highlights three potential issues. First, mechanical integrity testing is mandated for storage wells annually (temperature and noise logs) and bi-annually (pressure testing), raising a potential latency issue. For example, integrity problems could arise between tests. Second, adding real-time pressure monitoring for all well annuli at UGS facilities is acknowledged to be a major undertaking and involves a significant risk trade-off for aging wells, and some wells may remain unmonitored. Third, all of the above is focused on wells but not components of UGS surface infrastructure that may also be significant hazards. Additionally, the complex configuration and situation of some oil and gas fields can introduce ambiguities that cloud UGS risk assessment efforts (summarized below). Despite significant resources applied to monitoring Aliso Canyon during and following the 2015 Aliso Canyon incident, there remain unresolved questions about potential residual gas leakage there (also summarized below). These points raise the question of whether additional monitoring may be required to support robust risk management.

Natural gas at UGS facilities provides an atmospheric tracer that can enable efforts to monitor integrity of surface and subsurface infrastructure, potentially offering early warning to minimize the impact of leaks and avoid loss-of-containment and other hazardous situations for some failure modes[9]. Methane in particular is both the primary constituent of natural gas (typically about 96%) and can be measured by a variety of methods to identify, diagnose, and guide responses to integrity issues. Methane also serves as a proxy for other compounds that may be co-emitted, including air toxics such as benzene. Leak detection based on atmospheric measurements can be challenging at UGS facilities given the large quantity of components (wells, pipes, and other surface infrastructure) that are often distributed over large areas and in some cases, complex terrain. Isolating leaks to specific components and process attribution can also be complicated by other, nonstorage infrastructure within or adjacent to a UGS facility. In the following section, we present a case study of experiences with methane monitoring at Aliso Canyon and Honor Rancho, to illustrate the capabilities and limitations of different methodologies, including their potential use as complementary “tiers” in an observing system.

9. The possibility the 2015 Aliso Canyon incident might have been preceded by a smaller leak that could have been detected before the main blowout remains an open question and may not be resolvable with data from measurement systems that were in operation at that time.

1.5.3.2 Case Study: Monitoring System Capabilities and Limitations

Aliso Canyon has a combination of gas storage and oil production wells and surface infrastructure involving 12 operators, as well as a number of abandoned wells that are not readily accessible. These facilities and their immediate environs span nearly 20 km^2 of rugged mountainous terrain. Figure 1.5-5 illustrates this complexity as well as the locations of persistent “fence-line” monitoring systems established by SoCalGas and SCAQMD following the 2015 Aliso Canyon incident. The latter systems in principle can provide low-latency detection and quantification of major gas leaks; however, their utility is limited to favorable wind conditions, specifically, these systems are only sensitive to Aliso Canyon emissions when winds are from the north. Also, accurate interpretation requires sophisticated tracer-transport models that can address the complex interaction of winds and terrain in the area. We are unaware of any such modeling capability currently established for routine, operational use at Aliso Canyon or other California UGS facilities. Currently, each of the wells highlighted in blue in Figure 1.5-5 (operated by SoCal Gas) are subjected to daily surveys with hand-held gas analyzers, offering the ability to find small leaks at wellheads but offering little information about the rest of the facility. The status of monitoring protocols for the nonstorage wells and surface infrastructure in Aliso Canyon is uncertain.

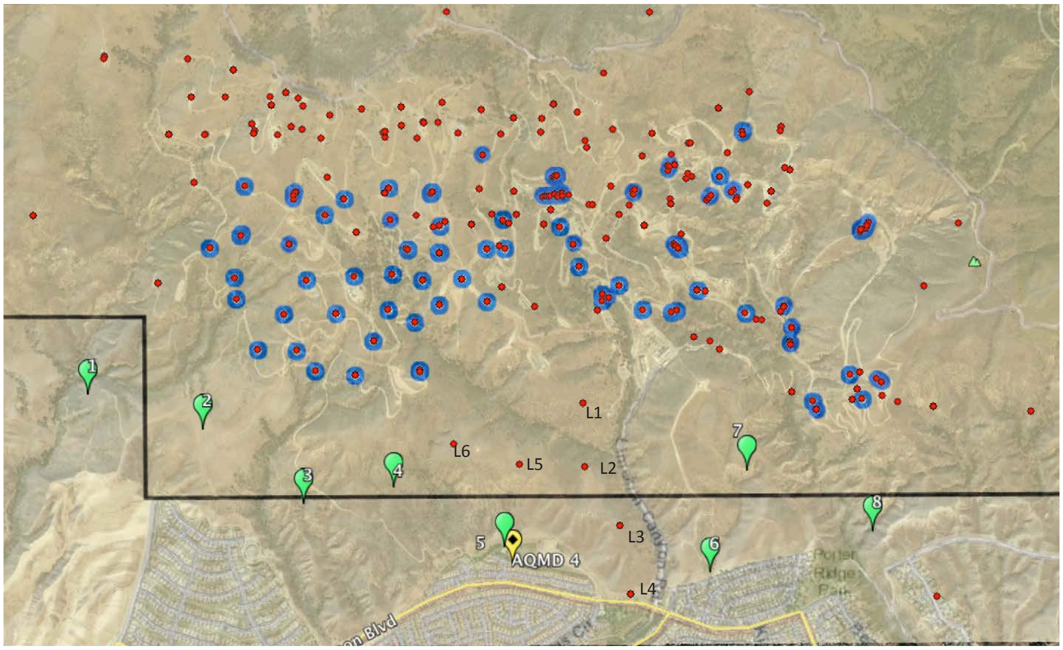


Figure 1.5-5. Aliso Canyon shaded relief where the red dots indicate 251 known wells within the Aliso Canyon field plus several nearby wells [source: DOGGR well finder], and the blue circles indicate the 115 UGS wells operated by SoCalGas that were known to be connected to the gas reservoir at the time of the SS-25 incident (only a subset are currently connected). The remaining wells are operated by 11 other companies or reported as abandoned. Some of the older wells are not readily accessible from roads (e.g., Limekiln wells L1-3, L5-6). All of these wells and associated surface infrastructure have the potential to release methane and other compounds, which presents a challenge for some monitoring systems to identify and discriminate emission sources. The green pins indicate the locations of eight new "fenceline" infrared sensors recently installed by SoCalGas. The yellow pin indicates a persistent methane monitoring site operated by SCAQMD. These systems provide persistent and near-real-time monitoring of local methane enhancements, but are only sensitive to Aliso Canyon emissions under northerly wind conditions and require sophisticated modeling to interpret.

At the time of the 2015 Aliso Canyon incident in Fall 2015, there was no reported quantitative monitoring program for ambient methane or other trace gases at Aliso Canyon (or any other UGS facility in California). At that time, leak detection was limited to infrequent Mechanical Integrity Testing of wells and daily on-road surveys by facility operators "sniffing" for odorized gas. The SS-25 well blowout was initially reported on October 23, 2015, based on such a survey. Several weeks passed before the first quantitative leak-rate estimates could be made. In the months that followed, a variety of methane measurement methods were deployed to improve confidence in the leak rate, as it evolved in response to efforts to regain control of the well and withdraw reservoir gas to lower reservoir pressure. Two of those methods included airborne surveys using low altitude *in situ* sampling and high altitude remote sensing, described in Section 1.5 and Conley et al. (2016) and Thompson et al. (2016). Figure 1.5-6 illustrates the unique capability of both methods to rapidly[10] assess gas emissions from complex UGS facilities: Scientific Aviation's Mooney aircraft equipped with a Picarro *in situ* methane analyzer and remote sensing by JPL's Airborne Visible/Infrared Imaging Spectrometer (AVIRIS) on the NASA ER-2 aircraft.

10. "Rapidly" requires a caveat. Neither of the airborne systems described here are currently used for routine surveys and their ability to deploy in a rapid-response mode is limited by other research commitments. However once the aircraft is deployed, assessments of a given UGS facility in California can usually be conducted within a few hours.

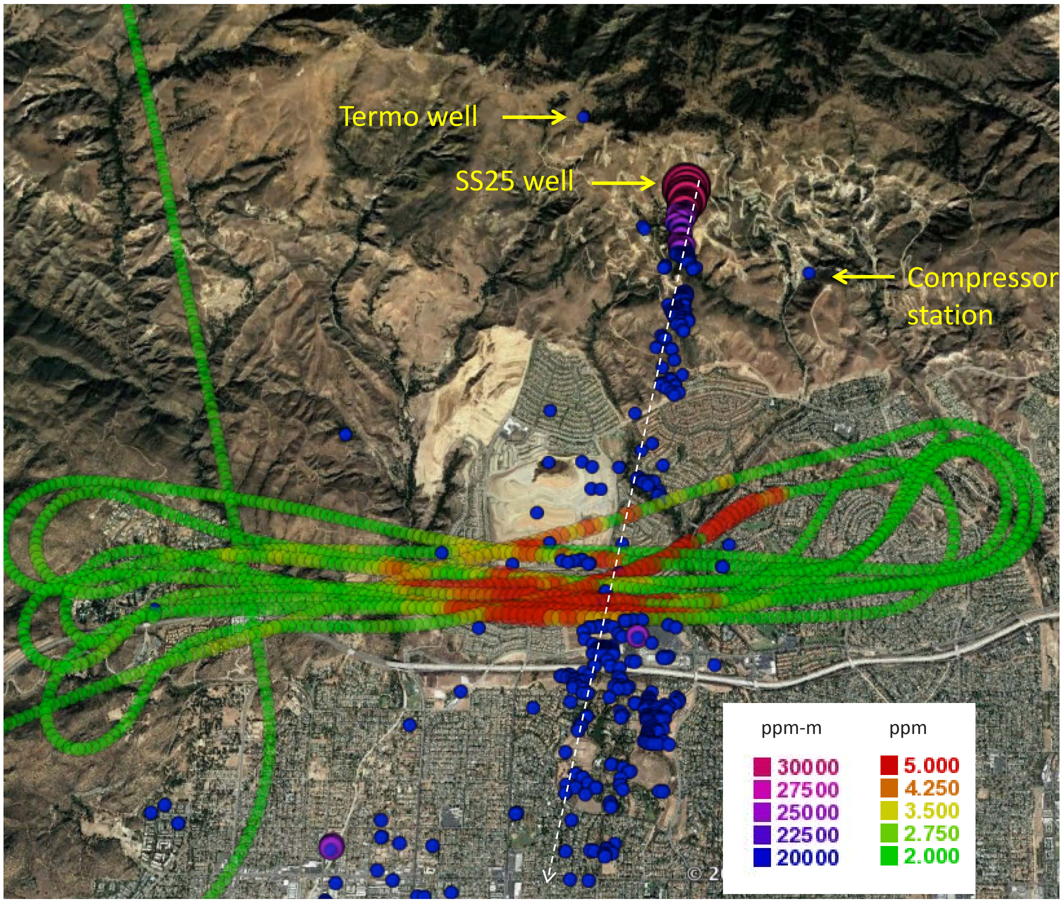


Figure 1.5-6. Application of two airborne measurement systems to assess methane emissions from the 2015 Aliso Canyon incident over a two-hour period on January 12, 2016: Scientific Aviation's Mooney aircraft equipped with a Picarro in situ methane analyzer and JPL's AVIRIS infrared imaging spectrometer on the NASA ER-2 aircraft. The white dashed arrow indicates the NNE wind direction. The data points indicate enhancements in methane mixing ratios in the gas plume beyond ambient background levels. Scientific Aviation flew a series of "curtain" profiles approximately 5 km downwind of the SS-25 leak source to sample methane from near-surface to the top of the planetary boundary layer (red-yellow-green scale). That enabled an accurate net emission rate estimate for the facility (~20,000 kgCH_4/hr). AVIRIS flew nine times over the facility during this time at an altitude of 8 km each with a swath width of 5 km and 6 m pixels. AVIRIS column-averaged methane values are shown with units of ppm-m (Blue-Magenta scale with higher values indicated by larger circles; 20,000 ppm-m column averaged enhancement is equivalent to a 2.5 ppm surface enhancement). AVIRIS derived a direct estimate of the leak rate (within 10% of the Scientific Aviation number) and also identified multiple sources within the facility including the SS-25 main leak, venting from the adjacent hillsides, the compressor station, and associated gas venting from an adjacent (Termo) oil well, subsequently verified by SCAQMD surface measurement.

The airborne *in situ* method offers a fast, highly accurate estimate of net facility methane emissions without the need for sophisticated tracer-transport models; however, it cannot resolve emissions to individual infrastructure components. Additionally, in this case the method was limited to northerly wind conditions because the steep terrain required downwind curtain flights over Porter Ranch rather than the cylindrical flight pattern normally used for other facilities (Figure 1.5-2). AVIRIS was able to pinpoint individual sources within Aliso Canyon, including two previously unreported secondary vents on the hillsides surrounding the SS-25 well, and also associated gas being vented from an oil well to the northwest, attributed to an inability to deliver gas to the shut-in Aliso Canyon storage field (Duren et al., 2017). Emission rates were directly estimated for the SS-25 leak source by scaling a Large Eddy Simulation with the AVIRIS methane retrievals, showing agreement to within 10% of the Scientific Aviation net facility estimate of 20,000 $kgCH_4$/hr (Duren et al., 2017).

Following the February 11, 2016, bottom-kill of the SS-25 leak, the Aliso Canyon facility remained in a shut-in state for nearly 18 months. During that time, periodic flights by Scientific Aviation tracked the evolution of the facility's methane emissions, which involved both the slow decay due to soil outgassing from the hillsides adjacent to SS-25 and unexpected episodic spikes[11]. Additionally, periodic on-road methane surveys through the facility by AQMD indicated several persistent methane plumes (Figure 1.5-7). While the observed worst-case methane emissions and plume enhancements during this period were orders of magnitude smaller than during the SS-25 blowout, they underscore the challenge in fully understanding leaks in complex locations like Aliso Canyon. While the sources of two of the observed methane plumes in Aliso Canyon are likely understood, the third remains a mystery. This is most likely owing to the incomplete spatial sampling of the wellhead surveys, on-road surveys, and periodic downwind airborne *in situ* measurement flights.

Figure 1.5-8 provides another example. Here, airborne remote sensing, using the next-generation AVIRIS (AVIRIS-NG) on a King Air aircraft at 3 km altitude, detected a persistent methane gas plume and identified the specific source: in this case, an emergency shutdown vent at Honor Rancho. On-road methane surveys confirmed the presence of the plume. The operator subsequently confirmed that the root-cause was a leaking bypass valve that was scheduled for repair.

Other measurement methods not described here include persistent regional scale tracer-transport inverse modeling using a network of *in situ* monitoring stations. Such systems have the potential to identify the sudden onset of a large LOC event at a UGS facility; however, they are typically unable to resolve methane fluxes below 1 km resolution, and the numerically intensive computer simulations often require weeks or months to run and

11. https://www.arb.ca.gov/research/methane/NG_Chart_All.png

verify. Another method involves tracer-release experiments (e.g., where a control gas such as N_2O is intentionally released at a known emission rate near the leak source and then detected along with the methane plume from the leak by downwind measurement sites, to enable accurate emission estimates of the leak). The tracer-release method is useful in cases where a leak has already been detected and located by other means. Finally, there are a variety of hand-held infrared cameras and methane sniffers that can provide rapid identification of gas leaks at very close range (typically a few meters from a source); however, these typically only provide qualitative information. The latter methods are typically employed with the aforementioned periodic manual surveys of wellheads.

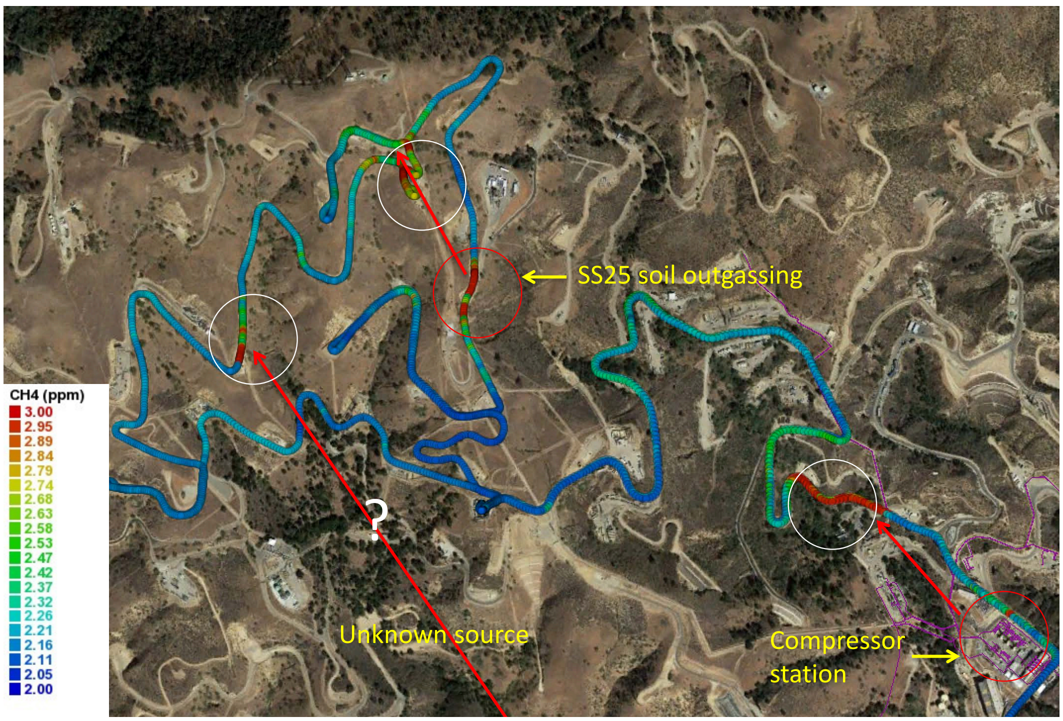


Figure 1.5-7. Example of an on-road methane survey using an in situ methane analyzer. The color scale indicates near-surface methane mixing ratios. Data were collected on July 8, 2016, roughly five months after the SS-25 leak was plugged. The facility was in a shut-in state. The red arrows indicate prevailing wind direction. This reveals several methane hotspots that exceed normal background levels, consistent with gas plumes crossing the roads. There were two likely methane sources: residual soil outgassing from the SS-25 incident and the facility's compressor station. The former is expected given earlier measurements of soil methane levels there. The latter suggests either venting associated with maintenance or a leaking component at the compressor station. The source of the third methane hotspot observed to the west is unclear. There are multiple UGS and producing and abandoned oil wells along the red arrow that could be responsible (data courtesy SCAQMD).

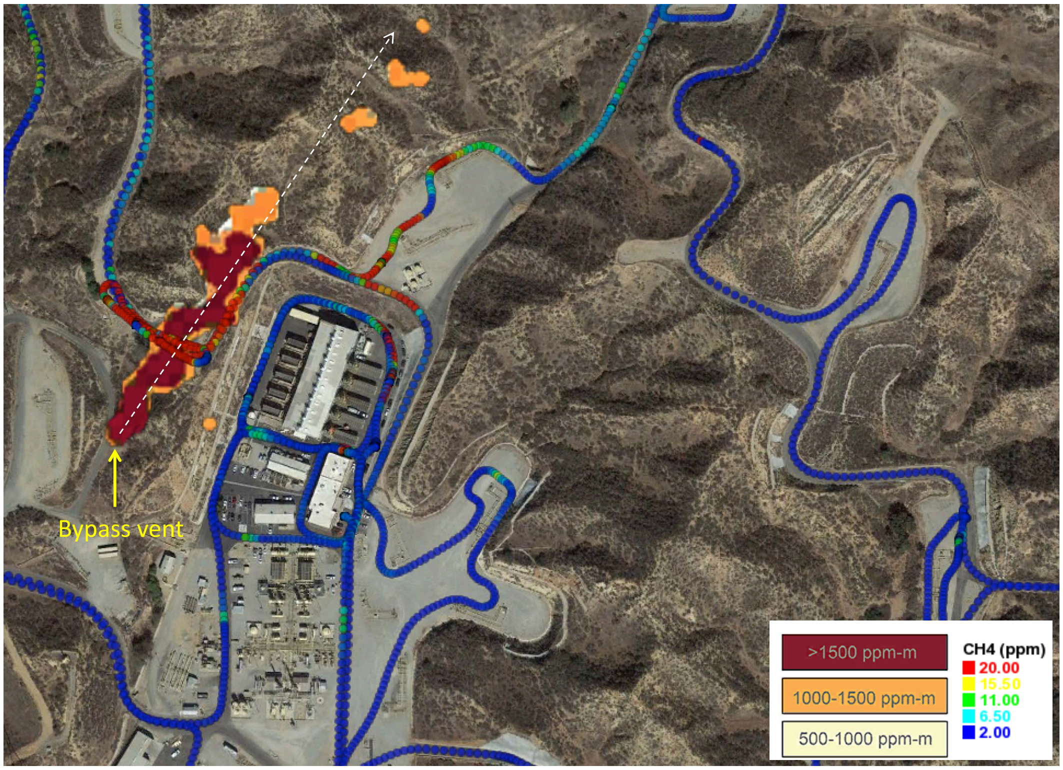


Figure 1.5-8. Example of a persistent gas leak at Honor Rancho discovered by AVIRIS-NG imaging spectrometer during a September 2016 over-flight (tan-brown color scale). The white arrow indicates the direction of the wind and methane plume. An emergency shutdown vent was identified as the source—attributed by the operator to a leaking bypass valve. The plume was detected on another day with the same wind conditions by an SCAQMD mobile survey (blue-red color scale); however, the exact source was not identified.

1.5.3.3 Recommendation for Atmospheric Monitoring for Integrity Assessment

Finding: Natural gas at UGS facilities provides an atmospheric tracer that can enable efforts to monitor integrity of surface and subsurface infrastructure — potentially offering early warning to minimize the impact of leaks and avoid loss-of-containment and other hazardous situations for some failure modes. Methane in particular is both the primary constituent of natural gas and can be measured by a variety of methods to identify, diagnose, and guide responses to integrity issues. Methane also serves as a proxy for other compounds that may be co-emitted, including air toxics such as benzene. There are many methane measurement methods that can be applied to UGS leak detection; however, they have differing capabilities and limitations. Several of these methods have been successfully demonstrated in operational field conditions at Aliso Canyon, Honor Rancho, and other facilities, including several examples that illustrate the potential for coordinated application of multiple synergistic observing system "tiers." As of October 1st, 2017, regulations of the California Air Resources Board (CARB) went into effect. These regulations require UGS operators to develop monitoring plans that need to be approved by CARB and also specify detailed repair requirements in case leaks have been detected. At a minimum, operators are required to continuously monitor meteorological conditions, including temperature, pressure, humidity, and wind speed and direction, monitor predominantly upwind (background) and downwind methane concentrations in air, and carry out daily gas hydrocarbon concentration measurements at each injection/withdrawal wellhead and attached pipelines (CARB, 2017c). If anomalous concentrations of hydrocarbons persist above certain thresholds for certain periods of time, notification must be made to CARB, DOGGR, and the local air district. It is important to note that the purpose of these monitoring requirements is to detect that leakage is occurring, not to quantify emissions (i.e., leakage rates). Once leaks are detected and located, they can be addressed. However, wellhead focused leak monitoring may not detect leakage coming out of the ground away froom the wellhead which may be indicative of a nascent or well-developed subsurface blowout.

Conclusion: Coordinated application of multiple methane emission measurement methods can address gaps in spatial coverage, sample frequency, latency, precision/uncertainty and ability to isolate leaks to individual UGS facility components in complex environments and in the presence of confounding sources. A well-designed methane emission and leakage-detection monitoring strategy can complement other integrity assessment methods—such as the mechanical integrity testing, inspections, and pressure monitoring now required by the new DOGGR regulation for storage wells (see Section 1.6) —by providing improved situational awareness of overall facility integrity. In addition to supporting proactive integrity assessments, methane emissions monitoring systems also help improve accounting of greenhouse gas emissions and timely evaluation of co-emitted toxic compounds in response to potential future incidents. (See Conclusion 1.12 in the Summary Report.)

Recommendation: An optimized methane emission monitoring system strategy should be devised to provide low-latency, spatially complete, and high-resolution information about methane emissions from UGS facilities and specific components of the UGS system. A program based on this strategy could benefit from a combination of persistent on-site measurements and higher accuracy, periodic independent surveys using airborne- and surface-based measurement systems. These emissions measurements would complement the concentration-based leakage-detection measurements required by CARB (CARB, 2017c). The scientific community should be engaged in helping UGS operators and regulators design such a strategy, and should be serving in an ongoing advisory capacity to ensure that best practices and new developments in monitoring technology can be implemented in the future. (See Recommendation 1.12 in the Summary Report.)

1.5.3.4 Recommendation for Assessment, Management, and Mitigation Actions In Case of Local Methane Leakage Observations

Finding: At Aliso Canyon, McDonald Island, and Honor Rancho, where total methane emissions have been measured to be above 250 kg/hr in some of the recent airborne measurement campaigns, the sources of these emissions were localized in most cases as originating from above-ground infrastructure such as compressor stations or leaking valves. This is a maintenance or repair issue but not an early warning indicator for large loss-of-containment events. (The 250 kg/hr emissions rate is a limit defined by DOGGR in its order allowing resumption of injection at the Aliso Canyon underground gas storage facility. If this limit is exceeded, the operator must continue weekly airborne emissions measurements until the leaks have been fixed, no new leaks have been found, and emissions are below 250 kg/hr.) But local methane hot spots could also be associated with wellheads or emissions from the ground near gas storage wells, in which case timely assessment and mitigation response can be essential in preventing the evolution of a small leak into a major blowout.

Conclusion: Periodic airborne and surface-based methane monitoring strategies provide the ability for detection of localized leaks within facilities, which in turn allow for early identification, diagnosis, and mitigation response to prevent smaller leaks from becoming a major loss-of-containment incident. (See Conclusion 1.13 in the Summary Report.)

Recommendation: We recommend that DOGGR or CARB develop a protocol for all facilities defining the necessary assessment, management, and mitigation actions for the cases in which periodic airborne and surface-based methane identify potential emission hotspots of concern. (See Recommendation 1.13 in the Summary Report.)

For example, if a leakage hot spot is located, the operator would be required within one week to provide to DOGGR or CARB a detailed assessment of the hot spots, with information on how large the leak is (flux or flow rate), what is leaking, where is it leaking from, etc. If the leak cannot be immediately fixed, the operator should be required to develop and present a plan within the following week of how to fix the leak. The follow-up would consist of agency staff visiting the site to observe the mitigation of the leak. We note that irrespective of leakage emission rate, the CARB regulations in place since October 1, 2017 outline a detailed time frame for fixing leaks detected on the basis of anomalous concentration, depending on concentration and duration thresholds.

1.5.3.5 Recommendation for Integration, Access, and Sharing of Monitoring/Testing Data

Finding: Since the 2015 Aliso Canyon incident, increasing institutional monitoring requirements, new regulatory monitoring/testing standards, and various measurement and data collection campaigns conducted in academic settings have provided a large amount of information on UGS facilities, in particular with regards to integrity issues and potential loss-of-containment. For example, airborne based measurements of local methane emissions can potentially offer early warning of well integrity concerns, which can then be followed up by detailed well integrity testing and mitigation. Meanwhile, persistent hotspots of gas odorants from environmental monitoring in communities might point to unknown gas leaks in nearby facilities. However, the value of these complementary data types is limited if they are not integrated and maintained in a central database and if access is only given after long delays.

Conclusion: We recognize the value of coordinated and integrated assessment of complementary types of data on methane emissions and other environmental monitoring to be able to act early and avoid potentially LOC incidents. However, we are concerned that there is no single data clearing house where (1) the multiple sources of data from required or voluntary reporting/monitoring are collected and maintained; and (2) these data can be easily accessed and evaluated by oversight bodies and the public. (See Conclusion 1.24 in the Summary Report.)

Recommendation: We recommend that these data, particularly on methane concentrations within and near the fence line of the facility and in key locations in adjacent communities, should be posted in real time, informing residents living nearby of potential airborne hazards associated with any LOC. Data that cannot be posted in real time, because more extensive quality assurance and control is required, should be released at frequent intervals without significant delay from the time of collection in a standardized digital format. (See Recommendation 1.24a in the Summary Report.)

Recommendation: We further recommend identifying a lead agency in California (e.g., DOGGR, CARB, CPUC) that develops and implements a strategy for the integration, access, quality control, and sharing of all data related to UGS facilities integrity and risk. (See Recommendation 1.24b in the Summary Report.)

1.6 RISK MITIGATION AND MANAGEMENT

1.6.1 Abstract

This section reviews (1) key elements that must be included in an effective risk management plan (RMP) for a UGS facility; (2) potential additional practices that could improve UGS integrity; and (3) regulatory changes under way by DOGGR covering UGS integrity, with comments on the new CARB methane monitoring regulations for context. We outline the elements of a well-conceived site-specific RMP that must be based on a formal quantitative risk assessment (QRA), and we provide guidance on methodologies to perform rigorous risk assessment. We also provide guidance on a range of other attributes that an RMP must contain. Underlying effective risk management is the idea that there are risk targets or goals, the attainment of which guides risk mitigation activities. Our analysis includes a critique, with recommendations, of the draft DOGGR UGS regulation published May 19, 2017 that is under consideration at the time of writing this section. Some of the specific recommendations relate to the requirements for a site-specific RMP at a UGS site, including the need for each UGS facility to perform a quantitative risk analysis, to perform regular training of the operational staff using written procedures, and to collect failure data and off-normal event data to be compiled in a publicly available database. The current DOGGR draft regulation should explicitly address the importance and role of human and organizational factors, as well as safety culture. Another recommendation relates to the need for DOGGR or the industry to develop risk targets or goals to guide decision-making, while still other recommendations relate to specific sections of the draft regulations that require various monitoring and measurement activities to assess and mitigate well integrity issues.

1.6.2 Introduction and High-Level Conclusions/Recommendations

1.6.2.1 Introduction

In California, the subsurface portions of UGS facilities have been regulated on the state level by DOGGR, both prior to and since the Aliso Canyon incident. DOGGR considers the subsurface portion as including the reservoir used for storage, the confining caprock, gas storage wells and wellheads, observation wells, and any other wells approved for use in the project. The California Public Utilities Commission (CPUC) regulates the surface infrastructure at UGS facilities. The California Air Resources Board (CARB) regulates greenhouse gas (GHG) emissions from UGS facilities as of October 1, 2017 (CARB 2017c). Until early 2017, federal regulation did not provide operational, safety, or environmental standards for the subsurface portions of UGS. Although the Natural Gas Pipeline Safety Act of 1968 has been found by a U.S. District Court to provide authority to PHMSA (the U.S. Pipeline and Hazardous Materials Safety Administration) over such facilities, until 2017 the agency declined to develop regulations around them, stating in a 1997 Advisory Bulletin that operators should consult industry guidelines and state regulations on the subject. Meanwhile, underground gas storage has been excluded from the U.S. EPA's Underground Injection Control program which regulates various types of fluid injection into the subsurface under the Safe Drinking Water Act (e.g., liquid waste, oil and gas waste water, CO_2, etc.).

In the immediate aftermath of the 2015 Aliso Canyon incident, DOGGR moved ahead to develop emergency regulations (California Natural Resources Agency, 2016) for the existing UGS facilities in the State. These emergency regulations were intended to quickly and efficiently reduce the LOC risk of these facilities, focusing mainly on the subsurface portion of UGS as described above. These emergency regulations will be superseded in January 2018 by permanent regulations now under development. DOGGR published on May 19, 2017 a draft of these new permanent regulations (California Natural Resources Agency, 2017), which we reviewed in this study. In addition to various new technical and administrative requirements, the emergency regulations and the proposed new permanent regulations require that each UGS facility in California must develop and implement a Risk Management Plan (RMP) with certain specified features.

Meanwhile, in December 2016, PHMSA introduced an Interim Final Rule (IFR) that incorporated two American Petroleum Institute (API) Recommended Practices (RP) (API RP 1170, "Design and Operation of Solution- mined Salt Caverns used for Natural Gas Storage," issued in July 2015 (17), and API RP 1171, "Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs," issued in September 2015). The IFR became effective as of January 18, 2017. States are now required to adopt the federal standards but they may certify, as did California, to act as PHMSA's agent and impose their own rules that go beyond the federal standard. DOGGR's interim and proposed final rules go beyond PHMSA's IFR recommended practices. These are the rules that we have reviewed in this study, results of which are given below.

The five prior sections of this report (Sections 1.1-1.5) document and review the state of UGS in California and its attendant risks to workers, the public, the environment (e.g., via GHG emissions), and to gas supply reliability. In the section below (Section 1.6.2), we evaluate and discuss the risk management plans (RMPs) as they are specified and described by DOGGR in its draft regulations. Following that discussion, we present (in Section 1.6.3) additional elements of risk management that should be included in the required RMPs. Finally (in Section 1.6.4), we present some notes and recommendations regarding the regulation of UGS and the requirements of the proposed new DOGGR regulations (California Natural Resources Agency, 2017) in particular, along with comment on the new CARB regulations (CARB, 2017c).

1.6.2.2 High Level Conclusions and Recommendations

This section (Section 1.6) contains a number of conclusions and recommendations on various topics, some of which are highly specific and, although important, do not rise to the level of having policy implications. However, some of these conclusions and recommendations are judged to be of greater importance than the others, and they are presented in full here at the beginning of Section 1.6, with the understanding that the remaining text of Section 1.6 provides the basis and support of the following high-level conclusions recommendations.

Overall Assessment of DOGGR's New Emergency and Proposed Draft Regulations

Finding: The draft DOGGR regulations that will govern subsurface operations at UGS facilities in California contain numerous important provisions that will make UGS safer, and that will also allow for a better understanding of the levels of safety achieved at any specific UGS facility.

Conclusion: The existence of both the emergency DOGGR regulations now in place (California Natural Resources Agency, 2016) and the draft permanent regulations still under development (California Natural Resources Agency, 2017) represents a major step to reduce risk of LOC, particularly the requirement for each facility to provide a risk management plan; the requirement of the use of two barriers in wells, e.g., use of tubing and packer; and the requirements for well testing and monitoring. We conclude that the new regulations should profoundly improve well integrity at UGS facilities in California. (See Conclusion 1.14 in the Summary Report.)

Evaluating Risk Management Plans as a Major Element of UGS Integrity

Finding: One of the major and most important elements of both the emergency regulations and the draft permanent regulations is that each UGS facility in California must develop and implement a Risk Management Plan (RMP) with certain specified features as follows: "RMPs shall include a description of the methodology employed to conduct the risk assessment and identify prevention protocols, with references to any third-party guidance followed in developing the methodology. The methodology shall include at least the following: (1) Identification of potential threats and hazards associated with operation of the underground gas storage project; (2) Evaluation of probability of threats, hazards, and consequences related to the events."

Conclusion: Requiring risk management plans and risk assessment studies for each facility is an important step in ensuring UGS integrity, but the draft permanent regulations do not contain enough guidance as to what the risk assessment methodology needs to provide. (See Conclusion 1.15 in the Summary Report.)

Recommendation: We suggest that DOGGR make further clarifications and specifications in the risk management plan requirements as follows: (1) the need for each UGS facility to develop a formal quantitative risk assessment (QRA), to understand the risks that the facility poses to various risk endpoints (such as worker safety, health of the offsite population, release of methane, property damage, etc.), and (2) the need to develop a risk target or goal for each risk endpoint that each facility should stay below and that is agreed to by the regulator (DOGGR), rather than written into an enforceable government regulation. These two needs, if satisfied, will provide the basis for rational and defensible risk-management decision-making that would not be possible without results from a formal risk assessment and defined risk targets and goals. We also provide guidance on a range of other attributes that an RMP must contain, including (1) consideration of human and organizational factors as well as traits of a healthy safety culture, and (2) recommendations regarding intervention and emergency response planning. (See Recommendation 1.15 in the Summary Report.)

As the text in this section explains, the development of the site-specific risk analyses can be accomplished in stages, the first stage being a scoping analysis to provide a short-term understanding at each UGS facility of the various risks and the issues that give rise to those risks. These risks can arise from natural hazards, from equipment failures either below or above ground, from human errors and organizational problems, or from a variety of other sources. These short-term scoping studies, to be supplemented later by more detailed analyses, can provide early guidance to decision-makers about what interventions may be needed, if it is concluded that some of the risks require early intervention to reduce either their likelihood of occurring or their consequences. We emphasize that the QRA recommended here need not be an exhaustive probabilistic risk assessment requiring multiple man-years of effort for every conceivable failure scenario, although it is always important to support any such analysis with relevant data that have an adequate pedigree in terms of quality. Instead, we recommend that a formal and practical risk assessment be carried out for the most important risk categories and failure scenarios. The state-of-the-art QRAs currently offered by several engineering consulting companies can provide the adequate rigor. In parallel, an activity needs to begin promptly to develop the risk targets or goals that will ultimately guide risk-mitigation decision-making. Whether this process should be led by the industry or by a government agency is a decision that is beyond the remit of this CCST study; however, the development process definitely requires broad stakeholder input.

Recommendations Regarding Specific Well Integrity Requirements

Finding: The proposed regulations contain various technical requirements for (1) well construction, (2) mechanical integrity testing, (3) monitoring, (4) inspection, testing, and maintenance of wellheads and valves, (5) well decommissioning, and (6) data and reporting. Overall, the Steering Committee finds these requirements a major step forward to improve well integrity in UGS facilities. In terms of the detailed specifications, the committee has several suggestions for revision, e.g., to clarify ambiguous language, provide additional specification, ensure consistency with industry standards, and balance the benefit of frequent testing with the risk to aging wells from installing instrumentation. These detailed suggestions are given in Section 1.6.4 of the report.

Conclusion: The technical requirements for wells provided in the draft DOGGR regulations contain many provisions that are expected to enhance the safety of well operations at the UGS facilities in California. As with any new regulation, application in the practice over time will be an ultimate test, with an “effective” regulatory framework being one that enhances safety to the point that risks are acceptable, while not placing unnecessary burden on operators. (See Conclusion 1.16 in the Summary Report.)

Recommendation: We recommend that DOGGR considers several detailed suggestions made in this Section 1.6 to improve the specific well integrity requirements in the draft regulations. Also, we recommend that the finalized regulations be reevaluated after perhaps five years of application. (See Recommendation 1.16 in the Summary Report.)

Need for Regular Peer Review or Auditing of New DOGGR Regulations

Finding: It is a common practice in many fields to evaluate the effectiveness of regulations, in particular those that may have been newly developed, on a regular basis by peer-review teams or auditing teams. For example, the Groundwater Protection Council (GWPC) organizes peer reviews of the Class II Underground Injection Control Program in certain states to which the U.S. EPA has delegated regulatory authority. (Class II wells are used only to inject fluids associated with oil and natural gas production—not gas storage.) The peer reviews typically include regulators from other states that are involved in those same programs, but may also involve stakeholders from academia and environmental organizations. Although many different approaches have been used and models for organizing them are widespread, one possible suggestion is to use the Interstate Oil and Gas Compact Commission (IOGCC) to help with this review.

Conclusion: Conducting a peer review or audit of the new DOGGR regulations after a few years of implementation would ensure that (1) the latest science, engineering, and policy knowledge is reflected to provide the highest level of safety, (2) these regulations are consistently applied and enforced across all storage facilities and are thoroughly reviewed for compliance, (3) an appropriate safety culture has been fully embraced by operators and regulators, and finally (4) the regulator has the necessary expert knowledge to conduct a rigorous review of the regulatory requirements. (See Conclusion 1.17 in the Summary Report.)

In contrast to purely prescriptive regulations, the risk management planning and analysis to be conducted as part of DOGGR's new regulations requires judgment-based decisions by the risk "assessor" where expert knowledge comes into play. A risk analysis, for example, requires decisions about which risk scenarios to consider (or not), the probability associated with a certain accident scenario, or what the uncertainties are about probabilities and impacts. It follows that regulatory review of such risk analysis requires expert knowledge in order to agree or disagree with the assumptions going into the analysis.

Recommendation: The Governor should ensure that the effectiveness of the DOGGR regulations and the rigor of their application in practice be evaluated by a mandatory, independent, and transparent review program. Reviews should be conducted at regular intervals (e.g., every five years) following a consistent set of audit protocols, to be applied across all storage facilities. Review teams would ideally be selected from a broad set of experts and stakeholders, such as regulators from related fields in other states, academia, consultants, and environmental groups. Results from the mandatory review should be published in a publicly available report, with an opportunity for public comment.

Responsibility for the design and execution of the review program should either be with a lead agency designated by the Governor, or alternatively could be assigned to an independent safety review board appointed by the Governor. (See Recommendation 1.17 in the Summary Report.)

1.6.3 Risk Management Plans related to UGS integrity -- review and evaluation of key RMP elements and of DOGGR's proposed RMP regulations

1.6.3.1 Introduction and Objectives

The handling of high-pressure natural gas during UGS operations entails risk, i.e., the possibility (non-zero likelihood) of failure with consequences (e.g., injury, death, environmental contamination, and property damage). Risk at UGS facilities can be managed and reduced, but never driven to zero. Risks need to be managed by careful assessment, including the analysis of what UGS components or operations entail the most risk and how these risks can be reduced, and by proactively monitoring the operations to detect and address potential failures of various components before they fail, causing a potentially catastrophic incident.

Risk is an expression of the likelihood that an event leading to a loss or to other undesired consequences may occur, and the magnitude of those potential consequences if it does occur. Risk can therefore be lowered by reducing the likelihood of occurrence or the severity of consequences, or both. Preventing any initial failure from occurring is arguably the most effective way to reduce the risk of causing harm to people or to the environment. Risk assessment in the UGS industry focuses primarily on the estimation of risk to the public safety.

Risk assessment is both a design tool and a valuable tool for ranking potential risks during the operating lifetime of a storage facility, for prioritizing operational efforts to reduce the likelihood of leakage, and for guiding emergency planning. It can be used to assist decision-making on future land use in the vicinity of the pipelines and facility.

The first objective of this section (and of Task 1.6.3) is to provide *recommendations* as to what should be the scope and level of detail of a Risk Management Plan (RMP) to be used by the operator of a UGS facility, so as to assure its integrity against both catastrophic incidents and less serious loss-of-containment (LOC) scenarios including long-term or chronic leakage scenarios. The second objective is to *evaluate the RMP requirements in the draft DOGGR regulation* now under consideration.

As an introduction, we note here that the draft DOGGR regulations that govern subsurface operations at UGS facilities (California Natural Resources Agency, 2016) contain numerous important provisions that will make UGS safer, and that will also allow for a better understanding of the levels of safety achieved at any specific UGS facility. The existence of both the emergency DOGGR regulations now in place and the newer (final) ones still under development (California Natural Resources Agency, 2017) definitely represents a major step to reduce the likelihood of another SS-25-type incident, particularly due to the requirement of the use of two barriers in wells, e.g., use of tubing and packer (see the discussion of DOGGR's proposed new regulatory requirement 1726.5 below in Section 1.6.4.3).

Below, the seven elements of an effective Risk Management Plan will be described. We will also provide below a review and evaluation of the RMP requirements in the draft final DOGGR regulations. Our evaluation concludes that in many areas, the RMP requirements are effective and adequate, e.g., in the areas of emergency preparedness, documentation, and updating of the RMP, but in some other areas *they fall short of what is necessary* to assure that each individual UGS facility in California has an effective RMP that its management can use to manage the facility's risk effectively.

1.6.3.2 Background

In the aftermath of the 2015 Aliso Canyon incident, emergency regulations were developed (California Natural Resources Agency, 2016) governing certain activities at the 12 existing UGS facilities in California. These emergency regulations were intended to quickly and efficiently reduce the LOC risk of these facilities. These emergency regulations will be superseded by permanent regulations that are now under development (California Natural Resources Agency, 2017).

One of the major elements of both the emergency regulations and the proposed new permanent regulations is that each UGS facility in California must develop and implement a Risk Management Plan (RMP) with certain specified features. In response to the emergency regulations, each of the UGS facilities in California developed such a plan, but these are currently only tentative, and updated RMPs will need to be developed and submitted when the final regulations come into force.

There are a number of different types of consequences related to LOC that a UGS facility poses, and each needs to be managed separately. For example, LOC can arise from hazards affecting the subsurface and lead to impacts to groundwater (underground sources of drinking water (USDW)), or LOC can be acute and above ground, with potential for fueling fires and explosions with resulting injury or death at the site, or LOC can be slow and chronic, leading to GHG emissions that affect climate. As these examples suggest, consequences and the risks associated with them fall into different categories, and we will use the term *"risk category"* to refer to them.

<u>Risk category – a definition:</u> Here the term *risk category* is important to understand. If there is an off-normal event, be it minor or major, there are different end-points of concern, each of which maps into a "category" of risk. The most important risk categories are risks to the *public health and safety*, to the facility's *workers*, to the *environment* and *natural resources*, and to the facility's *infrastructure*. Each must be "managed," and each must be kept below whatever "acceptable" level has been established. (See Section 1.6.3.3 below.)

A facility's Risk Management Plan may or may not address all of these categories, and if mandated by regulations, the level of concern for the different risk categories may vary.

1.6.3.3 Acceptability of the Various Risks: Risk Targets, Risk Goals, Risk Acceptability Criteria

For any facility, the need for a Risk Management Plan rests fundamentally on the notion that the facility poses non-zero risks in each of the various "risk categories," and that those risks must be managed. Hence, the notion that a facility can continue to operate rests, either implicitly or explicitly, on the acceptability of the risks that it poses.

For most industrial activities—indeed, for most human endeavors more generally—society has not established explicit risk criteria that are used in determining whether the risks involved with that activity are "acceptable." This is as true for UGS facilities as it is for most other similar facilities. Given the difficulty of defining acceptable risks, an alternative approach, sometimes used in other technical areas, is the use of *risk "targets" or "goals,"* which do not have the force of explicit (go-no-go) specified acceptability criteria, but which provide to the facility operators and the public a *notional expression of a goal or target*, expressing the range of risk levels that are judged to be acceptable.

It is important to understand the distinctions between these various ideas, so to be clear about what the words mean, they will be explained (as we use them here) as follows.

- A *risk criterion* would be a level of risk that is in a regulation, and which is enforced in the sense that if the risk posed by a facility exceeds the criterion, the facility is in violation.

- A *risk target* or *risk goal* (and these two words are effectively synonyms in our usage and in how the community of risk professionals uses them) would be a level of risk that is agreed to by an industry-wide consensus and to which the regulatory agency concurs, rather than something written into an enforceable government regulation.

- The words *"risk target"* or "risk goal" mean that the management at each facility would know that it is <u>expected</u> to try to do what it can, within sensible technical and financial constraints, to achieve the goal or target, but that if the facility does not succeed, operations can continue if a reasonable explanation can be provided to the regulator about why the goal or target cannot be achieved, and the regulator agrees to allow continued operation.

As will be explained below, decision-makers who are charged with managing risks should have some sort of risk target or goal for each risk category in order to provide a basis for deciding how to go about risk management in a rational, defensible, and transparent way.

Unfortunately, no risk targets, risk goals, or risk acceptability criteria now exist for UGS facilities, which means that considerable judgment is required to support the risk decisions made pursuant to any UGS Risk Management Plan (or the risk decisions pursuant to any specific government regulatory scheme that aims at regulating UGS risks). This is true even if a technically strong risk assessment has been performed, an issue to be discussed below. This shortcoming, this absence of any risk targets, goals, or acceptability criteria, makes both the development of USG Risk Management Plans and their use complicated and controversial.

There is, of course, always a danger that if strict risk criteria, or even risk targets or goals, become an overarching end-in-themselves, the result could be that a facility's managers and operators will come to believe that achieving them means that the facility if *safe enough* – that is, that *no further safety improvements are needed.* This is an incorrect interpretation of what is intended here. Another crucial element of an appropriate safety philosophy is that even if the risk goals or targets (or risk criteria) are met, one must always strive to do better, while still accounting for the costs and other burdens involved. This is the "ALARA" concept (as low as reasonably achievable), which is discussed below in a separate side bar at the end of this section.

Recommendation: It is recommended that either DOGGR (as part of its regulations or policies) or the industry (perhaps through an industry consortium) determine, for each category of risk, a threshold level of risk, and promulgate these threshold levels as risk targets or goals. There are many possible ways in which a risk target or goal might be formulated, and of course for every risk category, a different target or goal is necessary. An example or two may suffice to provide the general idea.

One possible way of formulating a risk target or goal might be along these lines.

> *It should be the target or goal for each UGS facility that any uncontrolled release of methane to the environment larger than XX kilograms over a 24-hour period should have a mean annual likelihood lower than 10^{-4} per year.*

> *It should be the target or goal for each UGS facility that any accident at the facility or any uncontrolled release of methane to the environment that causes severe injuries or deaths of more than XX workers should have a mean annual likelihood lower than 10^{-5} per year.*

The numbers (XX) in these targets or goals are left unwritten here, and likelihoods are provided just as placeholders, for a good reason. Without a public process to obtain inputs from both the general public and the affected facilities, there is no way to know what the numbers should be; that is a policy issue that is beyond the scope here. But the numerical levels should not be set except after the give-and-take of an open and transparent public process. Also, when these targets or goals are being developed, it is vital that one describe just how risk will be managed using the targets or goals through engineering design, through operations, through measurements of various parameters, through the collection of failure data and human-error data to support the risk models, and so on.

It is also important that the process of developing these targets or goals keep at the forefront that the principal users of them will be decision-makers who manage risk, regulatory agencies who oversee the facilities, and members of the public who rightly want to know how much risk there is and how it is being managed. All of them deserve these targets or goals as a crucial tool in supporting their own decisions. The basic requirement in the draft DOGGR regulations concerning this issue is in the following sentence, taken from 1726.3(a):

> *The Risk Management Plan shall demonstrate to the Division's satisfaction that stored gas will be confined to the approved zone(s) of injection and that the underground gas storage project will not cause damage to life, health, property, or natural resources.*

This speaks to risks of "damage" to "life, health, property, and natural resources." However, the fundamental problem with this requirement is that, in the absence of a promulgated or agreed upon acceptable risk level or risk goal or target, it is impossible to "demonstrate" that a facility "will not cause" the undesired endpoints. Because there is no such thing as zero risk—there is always some likelihood that damage will occur—meeting the requirement stated as "will not cause" is impossible.

This fundamental dilemma (or mismatch between expectations and reality) can only be resolved fully by the promulgation of risk targets or goals for each endpoint mentioned (life, health, property, and environment and natural resources). Risk "targets" or "goals" are mutually agreed upon by operator and regulator, but do not have the force of a requirement.

The formulation of a risk target or goal should deal with some combination of how large an impact or consequence is unacceptable, or how frequent is too frequent for a given impact, or some combination. For other complex engineering systems (commercial aircraft, nuclear power plants, offshore oil rigs), various government agencies have dealt with this acceptable-risk issue in different ways, and there is no set prescription for how acceptable-risk levels should be formulated. An excellent review of precedents from the regulation of other industries is provided by Abedinisohi (2014).

As an example of how the issue of lack of risk targets and goals pervades everything else, how can one decide how much monitoring is needed (what to measure, how frequently, to what required accuracy)? How can one decide which of several risk-mitigation activities is best, or sufficient? The DOGGR draft regulation in 1726.3(a) states, in the very next sentence after the one quoted just above, the following:

> *In accordance with subdivision (b), the Risk Management Plan shall evaluate threats and hazards associated with operation of the underground gas storage project and identify prevention protocols that effectively address those threats and hazards.*

How can the facility RMP "evaluate" threats and hazards unless one knows to what extent a given threat or hazard matters? And how can the RMP "identify prevention protocols that effectively address those threats and hazards" unless one knows what the word "effectively" means? In common parlance, the word "effectively" should normally mean that the "prevention protocol" would cause the risk to drop below whatever risk level is targeted and/or acceptable. Without knowing what is acceptable, or what aspirational target or goal is to be used, we cannot determine which prevention protocols will be sufficient, and why. *The dilemma here is fundamental to all that follows.*

1.6.3.4 Risk Management Plans – Recommended Content and Level of Detail

Background

The study team's work on this topic began with a review of several RMPs recently submitted to DOGGR by UGS installations in California in response to the emergency UGS regulations. It was understood that these were hastily assembled, were tentative in character, and will be revised (perhaps extensively) after DOGGR's final regulations are adopted. The study team has had experience with RMPs currently used to assure the safety of other types of engineered systems. That experience has informed the work here. The study team also gained insights from the American Petroleum Institute's Recommended Practice 1173 (API, 2014) and various ISO (International Standards Organization) documents cited therein. Also, the emergency regulations and the draft final DOGGR regulations both include a discussion of the attributes that an RMP must contain. All of the above has informed the discussion below.

As a general matter, it is important to state that any organized approach to risk management through a "risk management plan," even if it does not meet all of the attributes described below, will be useful both in understanding risks and in reducing them.

Risk Management Plans—Recommended RMP elements

Below is a list of the seven recommended elements (scope, content) that an acceptable RMP for UGS facilities in California should have. A detailed discussion of each element follows in the subsequent sections.

- Element #1 of the RMP needs to establish activities to *understand the current "level" of risk* posed for each risk category. This is accomplished either by measurements, by analysis, by a comparison with other similar facilities, or by some combination.

- Element #2 of the RMP needs to describe activities to *compare* the current "level" of risk, category by category, against any risk *targets*, risk *goals*, or risk *acceptability criteria* that may apply.

- Element #3 of the RMP needs to describe activities to carry out *routine (or periodic) monitoring, data collection, and analysis*, to determine whether there is a change in the current "level" of risk for each risk category.

- Element #4 of the RMP needs to provide for *prevention and intervention activities* if the risk "level" (for any category) exceeds acceptable guidelines, or if there is a realistic concern based on monitoring or analysis that a problem could arise in the future—this is what the words "risk management" imply.

- Element #5 of the RMP needs to describe an *emergency response plan* that specifies various activities that are necessary while an accident scenario is developing and then afterward, and also specifies the roles and responsibilities of the several different government agencies, companies, and others in assuring that the emergency response is effective. The plan also needs to provide for regularly scheduled pre-planning drills against written procedures, for prepositioning of response equipment, for communications protocols, and the like.

- Element #6 of the RMP needs to establish the protocol(s) for documenting the results of the risk analyses, the periodic measurements, the intervention activities (if any), the results of the interventions, and any other information that the facility owner, the regulatory agency, and/or the public should know.

- Element #7 of the RMP needs to provide *guidelines for modifying the Plan* in response to new information, such as from the routine monitoring and analyses carried out within the Plan. Associated with this is the need for review and approval of the updated Plan.

The Risk Management Plan—Element-by-element discussion

RMP Element #1—Methodology for understanding the current "level" of risk

For UGS facilities, a useful understanding of the level of risk does not generally exist for each of the risk categories, *because no rigorous and quantitative facility-specific risk assessment has been completed at any California UGS facility, as best we can ascertain.* As will be discussed below, understanding the level of risk posed by a given UGS facility for each risk category, accomplished by completing a quantitative risk assessment (QRA), should be one major element of the Risk Management Plan, because it is an essential prerequisite to the execution of the rest of a useful Risk Management Plan.

The goal of this Element of the RMP is to provide guidance for understanding the current level of risk posed by the facility, risk category by risk category. This is accomplished by analysis, supported in part by measurements, failure data, a comparison with other similar facilities, or by some combination.

This RPM Element is the most critical of all, because unless the current "level" of "risk" can be understood, a firm technical basis does not exist to support any of the next three elements (comparison to risk guidelines, monitoring and analysis, and intervention).

The way risk analysts usually discuss their understanding of the risks posed by any activity is by using the term *"risk profile."* The risk profile must be facility-specific, and furthermore it needs to be specific to each category of risk. For any risk category, the risk profile includes not only the quantified likelihoods of different "amounts" of risk (such as numbers of health impacts, or dollar values of different types of property damage), but also the likelihoods of the various risks, an understanding of each specific accident scenario that contributes to the risk, and then the principal contributors to each accident scenario. The hierarchy for a risk profile is therefore as follows, starting at the highest level and working down into more detail:

- The risk profile for the facility as a whole
- The risk profile differentiated by risk category (for example, risks to public health and safety, to the facility's workers, to the environment and natural resources, to the facility's infrastructure, etc.)
- For each risk category, the risk from each important off-normal scenario (that could lead to a large accident under some circumstances)
- For each off-normal scenario, the principal contributors to that scenario (for example, failure of an item of equipment, corrosion of a pipe, a human error including those due to human and/or organizational factors, etc.).

Note that in the above, the words *important* and *principal* are used, even though the determination of which scenarios are important and which contributors matter most is always fraught with uncertainty and analyst judgment. The obligation of the analyst, as always, includes explaining where judgments play a role and to what extent.

The risk profile inevitably involves numerical values, which need support from facility-specific data, including the sort of data discussed below in Section 1.6.4.3:

- For the facility as a whole, the risk profile needs to be presented in terms of the *annual frequency* of different accidental scenarios characterized by different "risk endpoints" and different "sizes" of the impacts. However, this facility-level information is of less use to decision-makers unless the risk has been differentiated among the various risk categories.

- Within each risk category, the risk needs to be presented so that it differentiates among the various off-normal scenario types that contribute to the risk. For *each scenario type*, the risk needs to be presented in terms of the annual frequency of that scenario, and also in terms of which "risk endpoints" are involved and the "size" of the risk impact.

- For each scenario of importance, the contribution arising from *each contributing factor* (for example, failure of an item of equipment, corrosion of a pipe, a human or organizational error, etc.) needs to be presented in terms of the likelihood of failure or error expressed in that likelihood's natural units (per test, per trial, per year, and so on).

A discussion of the uncertainties in the numbers is also important, and no risk profile is complete without such a discussion, so that users of the risk-profile information can understand the uncertainties: their origin, their character, how reducible or irreducible they are, and why. The analyst should also attempt to identify, if feasible, where collecting additional data can reduce the uncertainties.

The principal contributors will always be highly scenario-specific. As examples, for one scenario, contributors could be the failure of a pump, followed by an overpressure failure of piping close to the surface; for another, they could be the failure due to corrosion of a well casing followed by a human error in failing to secure a valve; for yet another, an earthquake could cause damage to two or three different components.

Unless the scenario-specific failures that contribute to each serious accident scenario are understood, in terms of both "what" and "why," there will not be enough insight to understand how the risks posed by that scenario can be managed. That is, *intervention (either for prevention or mitigation) can only be confidently recommended if it is guided by an understanding of "what" and "why,"* leading to an understanding of why a proposed intervention makes sense.

A scenario-specific analysis: Note that in the above, the emphasis is on performing scenario-specific analysis. The community of risk analysis experts has long recognized that the appropriate way to understand risks from a given engineered facility must be by examining them *one scenario at a time* (Kaplan and Garrick, 1981). Furthermore, because each scenario has, almost by definition, a different likelihood per year of coming to pass, the analysis described here is by its nature *intrinsically probabilistic.* It is probabilistic in its basic building blocks (the likelihood of a given equipment failure, or of a degraded process such as corrosion, or of a human error), and it is probabilistic in how these basic building blocks are combined to develop the annual likelihood of the scenario.

Still further, given a scenario, there are different likelihoods of the various potential consequences, such as ranges of releases of an undesired chemical, or ranges of impacts on human health and safety (either to workers or to off-site individuals), or ranges of damage to the off-site environment.

One important factor that is sometimes overlooked is the contribution of human and organizational factors (HOFs) to the evolution of the off-normal scenarios of interest. Human errors, be they errors of commission or errors of omission, have been found to play a prominent role in the risk profiles of most complex engineered systems (Frank, 2008). It is therefore imperative that they be modeled in any UGS risk analysis. Some human errors can initiate a sequence that would otherwise not begin; others can exacerbate a sequence that would otherwise evolve toward a safe state; still others can cause a sequence involving modest consequences to produce much more important consequences instead. Fortunately, the risk-analysis community has been working on methods for addressing human and organizational factors in the analysis, including approaches for quantifying the likelihood of various human reliability issues (Reason, 1990; Reason, 1998; Barriere et al., 2000; Bley et al., 2005; Gertman et al., 2005; Forester et al., 2007). Work has also been under way to account for how humans can intervene positively to help stop a developing sequence or to mitigate its consequences (Reason, 1998; Reason, 2016; Meshkati and Khashe, 2015).

The relevant risk-analysis methodologies exist: For engineered systems like UGS facilities, a well-developed methodology exists and is widely used. It is commonly called "probabilistic risk assessment" (PRA) and can take many different forms. It is well beyond the scope here to present details of the various PRA methodologies—the relevant literature is extensive (Vesely et al., 1981; Hickman et al., 1983; Frank, 2008; Garrick, 2009; ASME/ANS, 2013). However, every PRA methodology must answer the following three questions (Kaplan and Garrick, 1981), which cover what has been written just above, although in different words. These three questions have become known in the community of probabilistic risk analysts as the "risk triplet":

What can go wrong? *[These are the scenarios.]*

How likely is each important scenario? *[These are the annual frequencies.]*

What are the consequences? *[These are the endpoint impacts.]*

One major insight from experience with PRA analysis of complex engineered systems is that delineating the various scenarios provides the bulk of the insights—albeit the insights are typically most useful when some understanding has been developed as to which ones are the most "important," and why. Whether the word "important" in the previous sentence is attached to the annual frequency of a scenario, or to its consequences, or both, or to the fact that major uncertainties exist, is of course something that is highly specific to each individual analysis.

Another major insight, as noted above, is that various human and organizational issues are often found to be among the important factors in affecting whether a given scenario develops into a serious accident, or not.

Recommendation: To complete Element #1 successfully, a facility-specific quantitative risk analysis must be undertaken. The risk analysis must provide a quantified estimate for each analysis "result," including an estimate of the uncertainties in the numbers, and must describe each important contributor in a way that supports later Risk Management Plan Elements (see below), such as comparisons with acceptable risk levels, decisions on further monitoring or analysis, decisions on intervention, and so on. Therefore, it is recommended that the proposed new DOGGR regulations should describe what must be accomplished by an acceptable risk assessment approach and methodology, along with information about how DOGGR will review a given approach and methodology to assure that it is adequate. Although each facility can select its own approach and methodology, this is necessary in the DOGGR regulations to ensure that sufficient rigor and thoroughness are used across all facilities in California. The methodology must address each risk category considered in the Risk Management Plan.

The relevant language in the DOGGR draft regulation states:

[from 1726.3(b)] The Risk Management Plan shall include a description of the methodology employed to conduct the risk assessment and identify prevention protocols, with references to any third-party guidance followed in developing the methodology. The methodology shall include at least the following:

1. *Identification of potential threats and hazards associated with operation of the underground gas storage project;*

2. *Evaluation of probability of threats, hazards, and consequences related to the events.*

This language speaks of "threats," "hazards," and "consequences" in a way that provides only the most minimal guidance as to what the risk assessment methodology needs to provide. The last word, "events," presumably refers to the threats and hazards, but it is not clear.

As discussed above, the approach generally taken by the community of risk-analysis experts, when dealing with an engineered facility, is to concentrate on identifying the major off-normal accident scenarios, one-by-one. This is because it is the various accident scenarios that need to be prevented (one-by-one) from occurring either with too high a frequency or associated with too large a set of end-point consequences, or some combination.

Fortunately, the DOGGR draft language does use the crucial word "probabilities," indicating that the methodology contemplated by DOGGR must be probabilistic in its formulation.

Recommendation: To address the issue raised here, we propose the following draft language capturing the concerns described above:

[proposed for 1726.3(b)] The methodology shall include at least the following:

1. *Identification of the most important potential accident scenarios associated with operation of the underground gas storage project, based on a detailed description of the characteristics of each facility (number of wells, age, operating scheme, etc.);*

2. *Evaluation of the frequency (for example, the annual probability) of each such accident scenario, and the range of consequences associated with it, including estimates of the uncertainties in the numerical values;*

3. *For each important accident scenario, identification of the principal equipment failures, the principal external initiating events if any (earthquakes, flooding, aboveground industrial accidents, etc.), the principal operational errors, and other aspects that contribute to each accident scenario, and for each a description and quantification of its role relative to other contributors in the evolution of the scenario;*

4. *For each scenario leading to an accidental release, identification of the important engineered or natural features that affect the extent of the various end-point consequences, and a quantification of their relative roles, including an estimate of the uncertainties in the quantification.*

The above proposed requirement, although specific in its detail, is crafted carefully to establish *what* type of analysis is required, and with what scope, but without specifying *how* that analysis is to be performed. Notice, however, that the requirement to evaluate scenario probabilities in (2) and the words "extent of the various end-point consequences" in (4) mean that the analysis must be intrinsically probabilistic—reflecting the fact that the various important scenarios have different annual probabilities of occurring and a range of possible consequences were they to occur.

The above approach is also predicated on an *a priori* identification of the various risk categories of interest—be they public health and safety, risk to workers, risk to the environment and natural resources, risk to the facility's infrastructure, or others. The analysis must be structured to concentrate (one by one) on whichever of these risks are deemed to be within the scope of the risk analysis.

One final comment is important. The approach outlined above uses the concept of *individual accident scenarios* as its *organizing principle.* This organizing principle can then become the focus of each subsequent activity in the Risk Management Plan. That is, it is how comparisons can be made between the existing risk profile and what is acceptable. It is how to determine which specific monitoring, data collection, and analysis activities are needed, and why. It is how to identify and then to evaluate the efficacy of various proposed intervention proposals, be they proposals to make an actual change, or proposals to add or intensify a monitoring activity. A variety of analysis approaches are in wide use to gain an understanding of how the various scenarios could develop, and in how the underlying failures or errors contribute. Methods such as Failure Modes and Effects Analysis (FMEA) can be important tools in this regard (Rausand and Hoylan, 2004).

An additional concern (and associated recommendation) deals with the topic of the role of humans (and especially of human errors) in risk assessments of UGS facilities. Specifically, in most complex engineered systems, and UGS facilities should not be an exception, an important fraction of all of the off-normal scenarios of interest are caused by human errors or are influenced by safety-culture considerations. This is due both to the difficulty in designing against such errors, and the pervading influence of a poor safety culture, if it exists, in affecting everything related to the safety of such complex systems.

Some examples of issues related to this topic (the role of humans in off-normal scenarios and the broader role of safety culture in achieving the facility's overall safety objectives) include (1) the possible reluctance of an operator or maintenance worker to report his/her own error for fear of recriminations, thereby depriving the rest of the organization with the opportunity to improve the operation by learning lessons from the error; (2) confusion in the chain-of-command during the response to an off-normal event; (3) short-cuts taken by a member of the operating crew that compromise safety in the interest of efficiency, and that are self-justified because "the risk of a problem is very low"; (4) failures in operating equipment arising from the disregard of maintenance procedures or standard protocols; and (5) cover-ups by one worker of the errors of another in the interest of short-term camaraderie. A host of other examples exists. This leads to the following "Concern and Recommendation":

One of the concerns with the specific technical details of the RMP guidance in the current DOGGR draft regulation is that the regulation emphasizes certain specific hardware failure issues (and corresponding monitoring activities) without the benefit of insights from a proper analysis of human and organizational factors in the risk profile for any given facility. There is also an emphasis almost exclusively on the "hardware" side of UGS facilities, without adequate consideration of various organizational factors and of whether certain human actions and errors, as well as safety culture, could be important contributors. To address this concern, a sensible Risk Management Plan must give appropriate emphasis to both categories (hardware/equipment problems and human errors including organizational factors) in a way guided by risk-profile insights.

Moreover, the importance of safety culture to promote safety in high-hazard industries, such as UGS, and the ones regulated by the Pipeline and Hazardous Materials Safety Administration (PHMSA), has been strongly emphasized in a recent study by the National Academy of Sciences Transportation Research Board [*Designing Safety Regulations for High-Hazard Industries* (NAS/TRB, 2017)]. This study has analyzed the use of management systems to promote safety in high-hazard industries and has recommended adopting "management-based" regulations to "infuse a greater sense of responsibility and accountability (i.e., safety culture) into the regulated firms" (parenthetical statement in the original, p. 32). According to this study, the underlying rationale for utilizing "management systems to promote safety in high-hazard industries" is that "safety risks, especially catastrophic risks, can arise from interactions among conditions and activities that are difficult to anticipate and may be specific to each firm or work site. Such context specific risks will be unknown to the regulator, especially in view of the diverse and complex operations characteristic of high-hazard industries… [such] regulations may be advantageous in situations where the sources of risk are complex and context specific, as is characteristic of low-frequency, high- consequence events." (p. 3)

Conclusion: The draft DOGGR regulations ignores how human and organizational factors, as well as a healthy safety culture, drive safety outcomes and performance. (See Conclusion 1.18 in Executive Summary.)

Recommendation: The final DOGGR regulations for UGS facilities should explicitly address the importance and role of human and organizational factors as well as safety culture, commensurate with their impact. DOGGR could follow the State of California's Department of Industrial Relations' (DIR) Occupational Safety and Health Standards Board and at least adopt the two new "Human Factors" and "Safety Culture" elements in the recently revised and updated CalOSHA Process Safety Management for Petroleum Refineries regulation, which became effective on October 1, 2017 (CalOSHA, 2017). In this context, DOGGR should also consider applying other related and applicable elements of the new CalOSHA regulation to UGS safety, such as "Management of Organizational Change." (See Recommendation 1.18 in Executive Summary.)

RMP Element #2—Comparison of the current "level" of risk against the any risk targets, goals, or acceptability criteria that may exist

The goal of this element of the Risk Management Plan is to provide guidance for performing a comparison of the current level of risk, as developed in Element #1, against any risk guidelines (targets, goals, or acceptance criteria) that may exist, be they established by the facility owner or by the regulatory agency. This comparison helps in answering the question as to *whether the current risk level is acceptable*, and if not, why not. As noted above, this comparison needs to be done for each risk category separately.

To perform Element #2, Element #1 must have been completed, so that there is an understanding of the facility's current risk profile, and in particular the level of risk for each category of risk.

The work in Element #2 then becomes one of comparing (category by category) the current level of risk posed by the facility with any risk targets, goals, or acceptability criteria that may exist. Here, one key issue is that there will inevitably be uncertainties in the understanding of the current risk level posed by the facility. Absent uncertainties, the risk comparison is not difficult. Given the uncertainties, some of which can be large but (more importantly) some of which may not be completely quantifiable, considerable judgment will often be necessary in making the comparison(s) required in Element #2.

RMP Element #3—Routine (or periodic) monitoring, data collection, and analysis

In the absence of risk management plans, past monitoring, data collection, and analysis at UGS facilities have not been guided by nor integrated with rigorous scenario-based risk assessment and risk mitigation approaches. This disconnect or lack of formal integration of monitoring, data collection, and data analysis activities with scenario-by-scenario risk assessment insights can lead to neglect of needed monitoring and/or unnecessary monitoring activities.

The goal of this Element of the Risk Management Plan is to provide guidance for performing monitoring, data collection, and analysis, so as to determine whether there is a change in the current "level" of risk for each risk category.

The execution of RMP Element #3, as for Element #2, depends on the completion of Element #1, so that there is an understanding of the current risk profile, leading to an understanding of the level of risk for each risk category and of the individual contributors, scenario by scenario. Understanding the uncertainties is also important. Only then can a sensible program be established to monitor and analyze the risk level, because only then will there be the knowledge to support a decision about *what to monitor, what to analyze,* and why. Specifically, which potential equipment failures, and which potential human errors, are in need of monitoring, data collection, and analysis to improve our understanding or to reduce our uncertainty? And equally important, which interventions might be feasibly undertaken if the monitoring and analysis activity reveals a problem?

Besides understanding which aspects of the facility and its safety culture and operation currently contribute most to the risk profile, additional items may be added to the list of those needing monitoring and/or analysis. Specifically, there is the need to supplement the information derived from the current risk profile with engineering judgment, because certain aspects of any engineered facility that contribute very little to the current risk profile (but could be major contributors under different circumstances) only have such modest impacts, because their failures are known to be currently very rare, or the effects of the failures are known to be modest under current conditions. But things can change over time. Therefore, if there is a major concern about the impacts of a failure, and if change over time is a concern, then a monitoring program is necessary despite that specific item's not contributing much to the current facility risk profile.

Recommendation: It is recommended that DOGGR require that monitoring, data collection, and analysis must be informed using the insights from a scenario-by-scenario risk analysis to assist decision-makers in determining what to monitor, what data to collect, what to analyze, and why. Especially for scenarios characterized by a low probability of occurrence but a potential for high consequences, only a risk analysis that identifies and characterizes them can reveal the optimal intervention(s) to reduce their potential consequences.

The relevant language in the DOGGR draft regulation is found in several different places in 1726.3. For example, 1726.3(c)(3) calls for the Risk Management Plan to incorporate mechanical-integrity testing; 1726.3(c)(4) calls for corrosion monitoring; 1726.3(c)(5) calls for monitoring of casing pressure and several other parameters; 1726.3(c)(7) deals with reservoir integrity; 1726.3(c)(8) deals with formation of hydrates; etc.

The RMP requirements, however, lack an explicit link to an underlying risk analysis that can describe the extent to which each issue requiring monitoring, data collection, and/or analysis is linked to a specific accident scenario, and if so how. For each monitoring or data-collection activity described in the RMP, one should have a technical basis for deciding (1) how often, (2) with how much detail or accuracy, and (3) how much uncertainty in the measurements is tolerable, and why.

Recommendation: Throughout the new DOGGR draft regulation are requirements for monitoring, data collection, and analysis. Each of these requirements must be linked directly to an underlying risk analysis that can support a determination of the technical basis for deciding, for that activity, (1) how often, (2) with how much detail or accuracy, and (3) how much uncertainty in the measurements is tolerable, and why. An explicit linkage in the language of the requirements to the specific accident scenarios at issue can help provide the technical basis for these decisions.

RMP Element #4—Intervention activities

As background, the word *intervention* here covers both activities that would prevent a safety issue from arising and activities undertaken to reduce the likelihood or mitigate the consequences arising from an existing safety issue once identified.

The description in the proposed DOGGR regulations of the elements required in the RMP does not specify the need for general criteria for when and how to decide what changes or interventions are needed to mitigate risks that are deemed too high. But before intervention activities are decided upon, clear decision criteria need to be developed and used, based in part on the acceptability of the risk. These criteria need to be described in the facility's Risk Management Plan.

The goal of this element is that the Risk Management Plan should describe those intervention activities that must be undertaken if the risk "level" (for any risk category) exceeds risk targets or goals or risk acceptable guidelines, or if there is a realistic concern based on monitoring or analysis that a problem could arise in the future. This is what the words "risk management" imply.

Element #4 follows logically after #2 and #3, because intervention is called for only when the risk-management decision-makers conclude either (i) that a risk is "too high" (from Element #2); or (ii) that, based on monitoring and analysis (Element #3), a change in the risk profile either has occurred or is in danger of occurring; or (iii) that reducing uncertainties is sufficiently important.

Intervention, in turn, can mean either an actual change (to a piece of hardware, or to a procedure guiding operator actions or maintenance activities), or an intensified monitoring activity. That is, using colloquial language, *intervention can mean either "fixing something" or "watching something more carefully."* Furthermore, although intervention is usually called for because an actual problem has arisen, it is not uncommon for intervention to occur because new information has told the decision-makers that there is too much uncertainty.

Recommendation: A Risk Management Plan must include a description of the decision-making process including criteria for undertaking interventions of various types. This is needed even though many of the details cannot be provided in the RMP, because each intervention is by its nature highly situation specific.

The proposed new DOGGR regulations do not contain language linking the intervention protocols directly to the various accident scenarios being addressed. In the proposed new DOGGR regulations, language is needed requiring this link. This must be part of the facility's Risk Management Plan.

The relevant language in the DOGGR draft regulation states:

[from 1726.3(b)] The Risk Management Plan shall include a description of the methodology employed to conduct the risk assessment and identify prevention protocols. …. The methodology shall include at least the following:

(1) ….

(2) ….

(3) Identification of possible prevention protocols to reduce or monitor risks, including evaluation of the efficacy and cost-effectiveness of the prevention protocols;

(4) Selection and implementation of prevention protocols.

This text is acceptable as far as it goes, but lacks a direct link to the organizing principle of the various accident scenarios. To accomplish this, the regulatory language should provide that direct link.

Recommendation: A change must be made to replace the words "prevention protocols" with "intervention protocols" everywhere in regulatory subsection 1726.3(b).

In the regulatory language of 1726.3(b) above, a change must be made so that (3) and (4) read as follows, where the proposed additional new language is in *italics:*

(3) Identification of possible intervention prevention protocols to monitor the facility's safety culture to reduce or monitor risks, including evaluation of the efficacy and

cost-effectiveness of the intervention prevention protocols, *linked to the specific accident scenario(s) affected by each proposed protocol*

(4) Selection and implementation of intervention prevention protocols, *linked to the specific accident scenario(s) affected by each proposed protocol.*

RMP Element #5—Emergency response plan

The goal of Element #5 of the Risk Management Plan is to provide guidance for the UGS facility's emergency response plan. As noted above, this plan must specify various activities that are necessary while an accident scenario is developing and then later, and also specify the roles and responsibilities of the several different government agencies, companies, and others in making the emergency response effective. The plan also needs to provide for regularly scheduled pre-planning drills against written procedures, for prepositioning of response equipment, for protocols concerning communications, and the like.

Emergency response plans are in place dealing with many other dangerous processes and industries, and there is vast experience with how they should be formulated, exercised, and kept up-to-date. Both the Federal Emergency Management Agency and agencies is each of the several states (including California) have general guidance and specific guidelines concerning standard practices (FEMA, 2010; FEMA, 2014; California Governor's Office of Emergency Services, 2012).

For UGS facilities in California, their emergency response plans, as contained in the current Risk Management Plans, are not now generally based on a careful understanding of a given facility's risk profile. This omission should be remedied.

Recommendation: A Risk Management Plan must include an emergency response plan that establishes both requirements and expectations, and that is based on a careful understanding of the given facility's risk profile.

RMP Element #6—Documenting the results

The goal of this element of the Risk Management Plan is to provide guidance for documenting the results of the risk analyses (the "risk profile"), the measurements, the analyses, the intervention activities (if any), the results of the interventions, and any other information that the facility owner, the regulatory agency, and/or the public should know.

Recommendation: A Risk Management Plan must include a description of what documentation is required, or desirable, and why. Depending on the circumstances, certain documentation requirements may be specified, and others suggested.

<u>**RMP Element #7—Guidelines for modifying the Plan**</u>

The goal of this element is to provide guidelines for the modification of the Risk Management Plan itself in response to the routine monitoring and analyses carried out within the Plan, or in response to information gathered during installation, startup, operation, maintenance of new or modified equipment, or arising from the introduction of new procedures. Associated with this is the need for review and approval of the updated Plan. Placing the guidelines for the Plan's own modification within the Plan itself provides pre-determined markers concerning the thresholds for modifications and the frequencies for considering them.

One final comment should be made about Risk Management Plans and their use in a regulatory environment. If DOGGR is to use the facility-specific RMPs to inform its regulatory decisions, it is likely that some training may be necessary so that the regulatory staff can obtain the full benefit of the insights that can be derived from these RMPs.

1.6.4 Potential Additional Practices That Could Improve UGS Integrity

The study team has identified the following three "additional practices," each of which has specific benefits but also entails certain costs and burdens. These are termed "additional" because they are not described in the proposed DOGGR regulations. Each of these will be discussed in turn:

- Training of the operating crew at each UGS facility to assure more effective response to off-normal conditions that could lead to large accidental releases

- In the event of a release of gas from a UGS facility, development at each facility of an ability to predict the site-specific and release-specific transport and fate of released gas in the environment and its effect on local populations and infrastructure

- Development of a system for routine reporting on safety issues as they arise at any UGS facility and the sharing of that information with other facilities and with the public.

1.6.4.1 Operating Crew Training

Regular training of operators and maintenance personnel can be a significant factor in decreasing the likelihood and also the severity of large accidents. This is true even if the training, which consists of written material or lectures, is offered only sporadically. When this training is linked to the use of written procedures to help the personnel to respond to off-normal conditions, and when the training involves regular periodic updates, the benefits are enhanced.

The use of training like this has been a hallmark of industries (such as nuclear power plants, commercial aviation, and refineries) for which an accident can involve very major consequences. It is why, for example, commercial aircraft pilots undergo extensive training, both before assuming their responsibilities and then on a continuing basis afterward.

In the discussion here, the word *training* will encompass both the use of procedures and the development of “teaching modules” that allow each individual to understand the phenomena, the timing, and the issues involved with the evolution of each class of off-normal event. This also implies that an analysis exists that has identified the major types of “accident scenarios” that threaten the facility, so that training and procedures can be targeted specifically to those one-by-one.

Indeed, a major benefit of this entire approach is that, for each accident scenario at issue, the analysis work done to support the training provides to the operating and maintenance personnel the benefit of the insights, experience, and careful analysis of engineers who have thought through appropriate response actions in advance. (See American Nuclear Society, 2014.)

One of the important findings is that, in general, training in conjunction with written procedures does not mean that the operators or maintenance personnel need to follow the procedures by rote. In part, this is because not all accident scenarios can be anticipated in detail. It is always imperative that personnel who are on-the-spot at the time when an off-normal event occurs must think through what to do and why, aided by the written procedures and the prior training, but not necessarily completely governed by them. Experience shows that the personnel present at the time are in a better position than anybody else to understand the context and the details of the events as they occur, and to think carefully about what best to do (United States Nuclear Regulatory Commission (U.S. NRC), 1980).

Therefore, the procedures, and the training in their use, are to be thought of as providing important guidance, but not binding requirements. See (GWPC and IOGCC, 2017) for further insights specifically tailored to the operation of UGS facilities.

Also, although this training should be mandatory, this does not imply that an operator or maintenance worker cannot work until the training has been completed. A flexible approach is needed, especially given that new employees typically do best if they use on-the-job learning in conjunction with the initial training (American Nuclear Society, 2014).

One key prerequisite must be accomplished. That is, an effort needs to be expended to *perform an analysis of the major potential accident scenarios*, one-by-one, so as to support the training and the written procedures. In the course of this analysis work, insights will reveal which potential accident scenarios must be emphasized in the training and supported by the written procedures (and why), and which don’t (and why). The expense to perform this analysis, while significant, will pay major dividends, and not only in helping to avert the major accident scenarios of concern. Experience in other industries has shown that training with procedures increases the reliability of the operations, thereby reducing the frequency of modest incidents that have lesser safety significance but can have important financial consequences, such as improvements in equipment problems, operational downtime, worker safety, and other areas (Frank, 2008).

The situation in California is probably typical. There is no California requirement at today's operating UGS facilities for the regular training of the operating and maintenance crew, nor for the use of written procedures to assist the crew in its response to off-normal conditions and events that might lead to a severe accident. (These procedures are sometimes referred to as "emergency response procedures.") Nor are there any ANSI standards or other similar documents that can provide a basis. Regular training and written procedures have been demonstrated in other industries to improve safety around off-normal conditions and events, and, as noted above with the observation that an important fraction of off-normal scenarios in most complex engineered systems can arise from human errors and safety-culture concerns, it is likely that UGS could benefit similarly from analogous training and procedures.

The importance of this issue calls for either an industry-wide collaboration or a government-mandated requirement. Perhaps the recommended training and procedures could best be brought into existence by an industry consortium that would voluntarily agree to undertake the work to develop the technical basis. Alternatively, perhaps the best approach is through a government (DOGGR) requirement. Either approach can work, but the decision is highly situation-specific, and beyond the ken of the authors of this report.

Conclusion: There is no California requirement at today's operating UGS facilities for the regular training of the operating and maintenance crew, nor for the use of written procedures to assist the crew in its response to off-normal conditions and events that might lead to a severe accident. Regular training and written procedures have been demonstrated in other industries to improve safety around off-normal conditions and events. It is likely that UGS could benefit similarly from analogous training and procedures. (See Conclusion 1.19 in Executive Summary)

Recommendation: It is recommended that at each operating UGS facility in California, a requirement be put in place for the regular training of the operating and maintenance crew using written procedures. This could be either a requirement developed and implemented voluntarily by the industry itself, or a requirement embodied in a government regulation. It is further recommended that the requirement above be placed in the Risk Management Plan section of the draft California UGS regulations. (See Recommendation 1.19 in Executive Summary.)

1.6.4.2 Capability to Predict the Site-specific and Release-specific Transport and Fate of Releases

In the unlikely event that an accident unfolds with the potential to produce a major accidental release of natural gas, there would be a clear benefit if the capability existed to predict in near real time the transport and fate of a large release to the environment of natural gas, and also to predict its impact on workers, the local population, property, and the broader environment. This is borne out of experience with almost every major disaster involving potential or actual releases of dangerous substances from a facility to the environment (Broughton, 2005; Perrow, 1984; U.S. NRC, 1980).

Ideally, each facility would possess this type of analysis capability, so that, in the event of an accidental release, the analysis in near-real-time of the releases and their likely fate could be available to allow for the protection of lives, property and the environment. The analysis capability should possess the following features:

1. It should be site-specific.

2. It should account for local weather conditions and other relevant local conditions (traffic, etc.) in real time.

3. It should be able to provide the desired analysis is close to real time, so as to assist local decision-makers in maximizing the protection of workers, the local environment, the local population, property, and the environment.

4. The analysis and its implications should be capable of being made broadly available to the public.

There is significant experience with analysis of this type, although most of it is for facilities that are somewhat different (Hanna et al., 2006; Lisbona et al., 2014; Mahgerefteh et al., 2006; McGillivray et al., 2014). The adaptation to UGS facilities is, however, straightforward. The U.S. Department of Energy maintains a capability to perform these analyses on an emergency basis that provides an excellent model for the capability needed here (Sugiyama and Nasstrom, 2015).

The analytical capability need not be in-house at each facility, and indeed it is probably less efficient to do it that way. More promising might be an arrangement in which a central analysis team or company, under contract to the various facilities, would develop the analysis capability, receive all of the relevant data from wherever they are developed, and maintain its expertise over the years by interacting with similar existing capabilities in similar industries.

Once developed, the analysis capability needs to be kept up to date, not only in terms of data inputs but in terms of advances in the state of the art. There would need to be periodic training of on-site personnel at each facility as to how to use and interpret the analysis outputs.

Of course, off-site emergency-responder organizations need to be tied in: police, fire, security, environmental and agricultural protection agencies, and so on. These entities would also need to be trained and to take part in periodic drills.

At today's operating UGS facilities in California, there is no requirement that each facility possess the capability (through analysis) to predict in near real time the transport and fate of a large release to the environment of natural gas, and also to predict its impact on workers, the local population, and the broader environment, despite the clear benefit to safety if this capability were to exist. Though not a requirement, it is clear that the ability to predict off-site and downwind impacts of major LOC incidents at UGS facilities would improve emergency response and increase safety of both on-site and off-site populations.

If a shared approach is chosen for developing and maintaining the analysis capability, much of the development cost could be shared among the many different UGS facilities. The cost of the capability's upkeep would also need to be shared among facilities.

The capability could also either be maintained within each operating company or be provided by contractual arrangements off-site.

The importance of this issue calls for either an industry-wide collaboration or a government-mandated requirement. That is, perhaps the recommended analysis capability could best be brought into being by an industry consortium that would voluntarily agree to undertake the work to develop the technical basis. Alternatively, perhaps the best approach is through a government (DOGGR) regulatory requirement.

Conclusion: Although a range of practical and sophisticated models are readily available for predicting the impacts of off-normal LOC events, there is currently no requirement for UGS facilities to possess, or have access to, atmospheric dispersion models that can predict the fate of natural gas emitted from a facility. Also, the lack of temporal and spatially varying emission data from each facility, as well as the past lack of reliable local meteorological data (now addressed by the new CARB regulations for methane emissions from natural gas facilities) (CARB, 2017c), make it difficult to accurately simulate the atmospheric dispersion and concentrations of gas leakage from UGS facilities. (See Conclusion 1.20 in Executive Summary.)

Recommendation: Each operating facility in California should arrange to develop a capability to predict the atmospheric dispersion and fate of a large release of natural gas to the environment in near-real-time, and the impact of such a release on workers, the local population, and the broader environment. The simulation capability should be developed by an independent (ideally single) institution with the technical capacity (i.e., modeling skills) and transparency that meet the public's demand for trust. (See Recommendation 1.20 in Executive Summary.)

One example of an institution with this skillset is the National Atmospheric Release Advisory Center at Lawrence Livermore National Laboratory in Livermore, CA, a national support and resource center for emergency planning, real-time assessment, emergency response, and detailed studies of atmospheric releases.

1.6.4.3 Database for Routine Reporting of Off-normal Events Relevant to Safety

Industries such as commercial aviation and the nuclear-power plant industry, always put safety as the first priority. These industries established a mandatory system for reporting all off-normal failures and errors, no matter how small. Actual "events" comprising a series of one or more failures in sequence are also reported. These are then compiled into a publicly available database (U.S. NRC, 2017b; Den Braven and Schade, 2003; Browder et al., 2010). This database, used by all, enables continuous improvements to be implemented.

The most important categories in which the improvements are realized are in equipment reliability and in human performance. The documentation of failure modes of equipment, for example, enables others with similar equipment (industry-wide) to learn how to avoid those failure modes or to mitigate their consequences. The documentation of human errors, either in operating the plant or in its maintenance, again enables others to learn from experience. And the documentation of events (sequences comprised of a series of failures) enables them to be studied to reduce their frequency or their consequences (Frank, 2008).

Although the insights derived from collecting and documenting these categories of errors, failures, and events accrue mostly toward improving the individual items or actions, less obvious are the benefits in reducing the likelihoods and consequences of potential major accident scenarios. Experience in other industries shows, however, that perhaps the most important benefit of the gathering and analysis of this information is that it occasionally leads to the identification of a previously poorly understood accident scenario; this scenario can subsequently be designed against or protected against by training and procedures (Garrick, 2009). This identification of a new or unsuspected possible scenario can then be shared industry-wide, something not possible without both the existence of a broad database and its careful analysis.

In short, this learning-by-experience approach is made possible by the existence of an industry-wide database that gathers data on equipment failures (major and minor), human errors (major and minor), and unusual events, including events characterized by dependent failures (in which a failure in item A directly leads to a failure in item B or to a human error affecting item B.)

When proposals for such an industry-wide database were first broached in the nuclear-power industry (after the Three Mile Island nuclear accident in 1979), three concerns were raised: (1) the *cost* to every facility from reporting everything and then the cost of its analysis, done by a central group; (2) the issue of *liability*—if you report it, somebody will be identified as liable and perhaps somebody will sue in court; and (3) *proprietary* and intellectual-property concerns would stand in the way of publicly reporting that, say, a specific company's pumps seemed to be failing more often than those of its competitors.

All of these concerns, raised at the time, needed to be addressed, but in the end, each of them was overcome by an industry-wide agreement, with regulatory concurrence, as to the urgent need and major value of the endeavor (U.S. NRC, 1979; Nuclear Energy Institute, 2014).

The specific features of such a system would need to be worked out by the industry in collaboration with the regulatory agency. However, the features of the system can be outlined without working out the details. Specifically, the “safety issues” within the scope would need to include not only major events or their precursor events but also data on failures of individual safety equipment items and data on operational and maintenance errors. The reporting would need to be mandatory and performed according to a specific guidance document. The system would also need to provide guidance on standardized methods for reporting the information and analyzing its significance. The database should include root cause evaluations, and a requirement for full disclosure and reporting of them, independent auditing, and a continuous-improvement process. The scope should also include management-system deficiencies. Finally, a central analysis group must be established to compile the database and also to analyze it, categorize it, and disseminate it. The cost of maintaining this central group would need to be borne by the various operating facilities, whose complaints about the cost can be rebutted mainly by the prospect (sure to be realized over time) of large operational improvements in reliability to be derived from the use of the failure data.

A few studies in the literature (Evans, 2008; Evans, 2009; Folga et al., 2016) have compiled incidents and events at UGS facilities, and these have been very useful in providing a historical overview of the worldwide UGS industry’s performance. However, even if studies like these were to be developed or updated on a regular basis, they would be no substitute for the database recommended here.

The development of a comprehensive database allows UGS operators and others to better understand the causes of off-normal events so that efforts to improve integrity management systems or other risk management programs will be more likely to reduce their number and severity. A comprehensive database can also be used to establish quantifiable performance measures by which the effectiveness of these plans may be evaluated.

There are good precedents for voluntarily reporting “safety-related” issues by industry professionals/individuals or companies to a central shared database. One analogous program is the Aviation Safety Reporting System (ASRS) in U.S. civil aviation, which allows airline pilots and other crew members to provide near-miss information on a confidential basis. ASRS, which is based on voluntary reporting and is administered by the National Aeronautics and Space Administration (NASA), analyzes the information and makes it available to the public and across the aviation industry worldwide for educational purposes to decrease the likelihood of aviation incidents and accidents.

At California's UGS facilities, as elsewhere, although modest off-normal conditions and events (equipment failures, human errors in operations or maintenance, and other failures that adversely affect or potentially can affect the safety, security, or environmental performance) can happen, there is no requirement that these situations or incidents be routinely reported and compiled into a database that would be shared broadly. Such a database should exist. Furthermore, the reporting of such events and failures should be mandatory and the data and any results of analyzing the data should be shared broadly. Absent such a database, opportunities are lost to learn from these off-normal events and failures, which would enhance safety, specifically by helping to reduce the likelihood and/or the consequences of less likely major accidents.

Conclusion: Experience from other industries shows that the reporting of minor off-normal events and failures can be very useful when shared and aggregated for the purposes of improving operations and learning from mistakes. (See Conclusion 1.23 in Executive Summary.)

Recommendation: It is therefore recommended that a database be developed for the reporting and analysis of all off-normal occurrences (including equipment failures, human errors in operations and maintenance, and modest off-normal events and maintenance problems) at all UGS facilities in California. An example of one kind of input to this database is the required reporting of leak detection and repair required under the new CARB regulation for methane emissions from natural gas facilities (§95673(a)(12) (CARB, 2017c)). The database should be made publicly available to enable others to derive lessons learned from it. (See Recommendation 1.23 in Executive Summary.)

The database should include root-cause evaluations, and a requirement for full disclosure and reporting of them, independent auditing, and a continuous-improvement process. The scope should also include management-system deficiencies. Once this publicly available database exists, the reporting of such events should become mandatory under a no-fault protocol. This requirement could either be embodied in a government regulation, or be a requirement developed and implemented voluntarily by the industry itself.

The recommended database and its custodian for the gas industry can follow the ASRS model, if a NASA-type research and development custodian can be found for the underground gas storage and pipeline industry. Alternatively, the entity could be modeled after the nuclear power industry's self-regulatory body, the Institute of Nuclear Power Operations (INPO). If it is to be in a California regulation, it is further recommended that the requirement above be placed in the Risk Management Plan section of the new draft of the California UGS regulations.

1.6.5 Regulatory Changes Under Way for UGS Integrity—Review and Evaluation

1.6.5.1 Background

Constructing and operating an underground gas storage facility in California requires that a Certificate of Public Convenience and Necessity be granted by either CPUC (or Federal Energy Regulatory Commission (FERC)), as described in more detail in Chapter 2 of this report. For the purposes of this section related to evaluating regulatory changes since the 2015 Aliso Canyon incident, we note the following:

1. UGS is explicitly excluded from the U.S. EPA's UIC program (see Section 1.2) so there is no oversight by U.S. EPA.

2. PHMSA had previously declined to exercise its authority to regulate UGS wells but began this year on January 18, 2017 through Interim Final Rule (IFR) to exercise its authority through the adoption of the recommendations in API 1171 (relevant to DHR storage) PHMSA (2016).

3. DOGGR regulates UGS wells in California, and in particular DOGGR grants permits to drill wells and sets well design standards.

4. CPUC regulates the surface infrastructure at UGS facilities, although DOGGR has an interest in this infrastructure to the extent that it interacts with DOGGR's own regulatory authority covering UGS wells.

5. The California Air Resources Board (CARB) and the various Air Quality Management Districts in the state collect information about emissions from all stationary sources in California, including UGS facilities. A discussion of this can be found in Section 1.4.5 earlier in this report.

6. CARB regulations on detection, reporting, and repairing natural gas leaks at UGS facilities went into effect October 1, 2017 (CARB, 2017c). We note that the measurements under these regulations are concentration measurements used to detect leakage rather than quantify emissions (leakage rates).

The context for the discussion in this section is that in the aftermath of the 2015 Aliso Canyon incident, emergency regulations were developed (California Natural Resources Agency, 2016) governing certain activities at the several UGS facilities in California. These were intended to decrease LOC risk and improve the safety of these facilities. These emergency regulations will be superseded by permanent regulations that are now under development (California Natural Resources Agency, 2017).

1.6.5.2 Scope of this Review

The proposed regulations contain both technical requirements and various administrative requirements. This review and evaluation will cover only the technical requirements. These technical requirements are grouped under the following section headings in the draft regulations. These will be reviewed below section-by-section.

1726.3	Risk Management Plans *[A review and evaluation of Section 1726.3 on RMPs can be found above in Section 1.6.3.]*
1726.4	Underground gas storage project data requirements
1726.5	Well construction requirements
1726.6	Mechanical integrity testing
1726.7	Monitoring requirements
1726.8	Inspection, testing, and maintenance of wellheads and valves
1726.9	Well leak reporting
1726.10	Requirements for decommissioning

1.6.5.3 Section-by-section Review

<u>Underground Gas Storage Project Data Requirements (Section 1726.4)</u>

The UGS regulations for project data require updated data to be submitted when changes to such data are available. Although a couple of examples are provided, the regulation is ambiguous in that it does not define what constitutes a change nor provide a timeframe for reporting such change.

The article (8)(b) in 1726.4 states, *"Updated data shall be provided to the Division if there are changes in operating conditions, such as gas plant or compressor changes, or if more accurate data become available, such as updated cross sections, new reservoir characteristics data, or new pressure flow modeling."* Changes in operating conditions can include a large number of elements which could or could not be relevant to the safety of the operations. To minimize misinterpretation and to achieve consistency in the data reported across all storage fields, we recommend a definition of relevant changes be included. Alternately, a list inclusive but not limited to, could be provided to aid operators with the task. It should be noted that, unlike the reporting for the Mechanical Integrity Test and well leaks, the regulations do not provide a timeline under which the operators are required to report the change.

Additionally, although operators of existing projects might have some or most of the data requested by the regulations, some might be old or difficult to retrieve. In light of the new regulations (and to aid the set-up of the record management program, if not in place) we would recommend an initial review of all existing data to date. This would help highlight gaps and discover inconsistencies, if any. There are many ways this could be achieved, either by on-site review, or submission of all data to the regulators. Other states' regulators have provided a checklist to assist operators in compiling all relevant data and identify gaps as relevant to the new regulations. A similar system could be utilized in California.
A checklist (or similar) would not necessarily be restrictive, but allow for flexibility in the options provided.

After a new site project has been approved (or an existing one reviewed under the new regulations) a periodic (every few years) review of all data should be applied. The scope of the periodic review is to maintain updated data, test the Record Management System and identify gaps or new needs.

The current UGS regulations also require the reporting of *'more accurate data if it becomes available'*.

Recommendation: To maintain consistency in reporting across the industry it is recommended that a definition of a change in the project data be provided. Additionally, a predefined timeframe for reporting such changes should be specified. Furthermore, we recommend a review of all data be done every few years.

Well Construction Requirements (Section 1726.5)

The UGS regulation (subsection (b)(1)(A)) seems to require the use of tubing with packer as a minimum to meet primary barrier requirements. That requirement seems inconsistent with other parts of the text. Additionally, the regulations do not address when or how often bond logs or alternative methods of cement evaluation are required. Inconsistencies were found in what is required as a primary barrier. Clarification is necessary on when and how often cement evaluation is needed.

As a general matter, the concept of more than one barrier between high-pressure gas and the environment is an excellent way to improve well integrity. The subsection 1726.5 (b)(1)(A) of the UGS regulations states that at minimum, the primary barrier should comprise production casing (i) and tubing with packer (ii). This statement suggests that both are required. Subsection b(11) states that *"For well equipped with tubing and packer […],"* suggesting that not all wells have a tubing with packer configuration. These two statements are inconsistent. According to the barrier definitions, if tubing alone is used for production and injection, then the tubing would be the primary barrier while the casing would be considered part of the secondary barrier. If production and injection are allowed in both then the casing would be considered the primary barrier.

Subsection (b)(1)(B)(i) requires that to meet the standard for the secondary barrier, the casing cement should overlap at least 100 ft between the concentric casing, with a good quality cement bond. What constitutes a good cement bond is not specified. Similarly, subsection (b)(7)(B)(10) requires that the cement bond log or evaluation show an adequate bond between the cement and the casing and the rock. A clarification on how and if these requirements are similar is suggested with an additional statement on district discretion on acceptable results as newer, more accurate logging tools became available.

Also, it is well known that cement bond quality will degrade within the well life cycle, especially if pressures are cycled periodically. The UGS regulations do not specify when, after curing and reaching appropriate compressive strength, the evaluation needs to be performed, nor if subsequent evaluations are required to gauge the aging of the cement.

Recommendation: Clarification of what qualifies as a primary barrier is recommended to avoid confusion. Because many of these wells are repurposed, i.e., conversions of existing, old oil and gas wells, we recommend that the evaluation of cement bond integrity be addressed throughout the lifetime of a well and not just at initial casing installation.

Mechanical Integrity Testing (Section 1726.6)

Demonstration of external and internal mechanical integrity is a critical aspect of maintaining well integrity in any UGS field. UGS regulations require annual temperature and noise logs to demonstrate external mechanical integrity and pressure testing for at least 30 minutes every two years for every active well to demonstrate internal mechanical integrity.

Subsection 1726.6 (a)(1) of the UGS regulations requires temperature and noise logs to ensure integrity. These logs are designed to evaluate the location of an external leak behind casing, if present. The reliance on cement, temperature, and noise logging evaluation to demonstrate external mechanical integrity requires that all logging operations are performed to industry standards.

Corrosion is a significant problem associated with well integrity in the UGS fields in California. Regulatory requirements address the need for corrosion logging and monitoring to evaluate corrosion effects on well integrity. Corrosion logging and monitoring operations are a reactive approach to the problem of corrosion impacts on well integrity.

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

Subsection 1726.6(a)(3) of the UGS regulations requires an internal well integrity demonstration by pressure testing of the production casing or of the tubing if injection is through the tubing with a packer system. Duration of the test is specified to be 30 minutes (or 60 minutes in special circumstances) with no more than a ten percent decline. If continuous pressure monitoring of the tubing and the production casing-tubing annulus using a SCADA system, is in fact implemented and is able to detect suspicious behavior, the frequency of these internal mechanical integrity tests could be decreased or even eliminated.

The UGS regulation requires notification prior to MIT testing and a report within 30 days of the test conclusion. Any well testing (and intervention) that is outside the normal operating procedure should also be reported irrespective of the reason for conducting it (yearly requirement) or the scope.

Recommendation: We recommend the following industry standards for logging to demonstrate external mechanical integrity:

(A) Temperature Survey. *A temperature survey performed to satisfy the requirements of external mechanical integrity testing shall adhere to the following:*

1. *The well must be taken off injection at least twenty-four hours but not more than forty-eight hours prior to performing the temperature log, unless an alternate duration has been approved by the DOGGR.*

2. *All casing and all internal annuli must be completely filled with fluid and allowed to stabilize prior to commencement of logging operations.*

3. *The logging tool shall be centralized, and calibrated to the extent feasible.*

4. *The well must be logged from the surface downward, lowering the tool at a rate of no more than thirty feet per minute.*

5. *If the well has not been taken off injection for at least twenty-four hours before the log is run, comparison with either a second log run six hours after the time the log of record is started or a log from another well at the same site showing no anomalies shall be available to demonstrate normal patterns of temperature change.*

6. *The log data shall be provided to the DOGGR electronically in either LAS or ASCII format.*

(B) Noise Log. A noise log performed to satisfy the requirements shall adhere to the following:

1. *Noise logging may not be carried out while injection is occurring.*

2. *All casing and all internal annuli must be completely filled with fluid and allowed to stabilize prior to commencement of logging operations.*

3. *Noise measurements must be taken at intervals of 100 feet to create a log on a coarse grid.*

4. *Noise logging shall occur upwards from the bottom of the well to the top of the well.*

5. *If any anomalies are evident on the coarse log, there must be a construction of a finer grid by making noise measurements at intervals of twenty feet within the coarse intervals containing high noise levels.*

6. *Noise measurements must be taken at intervals of ten feet through the first fifty feet above the injection interval and at intervals of twenty feet within the 100-foot intervals containing:*

   a. The base of the lowermost bleed-off zone above the injection interval;

   b. The base of the lowermost USDW; and

   c. In the case of varying water quality within the zone of USDW, the top and base of each interval with significantly different water quality from the next interval.

7. *Additional measurements must be made to pinpoint depths at which noise is produced.*

8. *A vertical scale of one or two inches per 100 feet shall be used.*

(C) Cement Evaluation Logging. A cement evaluation log performed to satisfy the requirements of this section shall adhere to the following:

1. *Cement evaluation tools shall be calibrated and centralized to the extent feasible.*

2. *Cement evaluation tools shall be run initially under surface pressure and then under pressure of at least 1,500 psi.*

3. *If gas is present within the casing where cement evaluation is being conducted, then a padded cement evaluation tool shall be run in lieu of an acoustic tool.*

(D) Anomalies. The operator shall take immediate action to investigate any anomalies, as compared to the historic record, encountered during testing as required. If there is any reason to

suspect fluid migration, the operator shall take immediate action to prevent damage to public health, safety, and the environment, and shall notify the DOGGR immediately.

A proactive approach to corrosion in UGS would be a more logical solution to addressing this problem, such as determining what is causing the corrosion of the wells and determining how to prevent it.

Monitoring Requirements (Section 1726.7)

The UGS regulations require real-time monitoring of all annuli. Mandatory reporting and follow up remediating actions are required for annuli that are found with pressure greater than 100 psi. These regulations have the potential to force operators to perform a large number of remedial actions with limited success rates. However, real-time pressure monitoring is a proactive approach in addressing and identifying potential incidents or releases and the benefits can sometimes outweigh the costs.

Currently, the majority of the existing wells are not set up to measure all annuli pressure, especially surface and intermediate. Although we agree that new wells should be required to be set up to monitor all annuli, retrofitting all existing wells in service would be a major undertaking.

Additionally, the UGS regulations require remediating action for any well that is found to have an annulus pressure greater than of 100 psi (for annuli that should not have any pressure). Although the presence of gas does indicate migration through the annulus, it does not necessarily reflect the severity of the breech. A remediating requirement, as it is currently stated, would result in an extremely large number of remedial actions. Remedial actions can vary considerably, but the potential for annular over-pressurization, which can result in a breakdown of the casing shoe and in a release at the surface, is a major concern for UGS wells.

Strategically placed observation wells in the vicinity of spill points, within an aquifer, and above the confining zones in porous and permeable formations should be installed and monitored to detect the presence or movement of gas from storage operations. Observation wells can be placed above, below, or laterally within the gas storage reservoir depending upon the geology of each gas storage project. These wells need to be placed within porous and permeable geologic formations capable of being monitored. The location and design of observation wells should take into consideration:

1. Observation wells located within the storage zone that are suitable for monitoring reservoir pressure, can be considered, but should be placed within the buffer zones in order to limit artificial penetrations within the gas storage field reservoir.

2. Potential migratory paths from the reservoir to another formation.

3. Fluid interface monitoring at the location of the reservoir spill point.

4. Permeable zones and stratigraphic traps above the storage zones.

5. Low-permeability zones, formations or fields adjacent to and in communication with the storage zones.

Observation wells should be constructed to the same standards and criteria established in the well construction guidelines for gas storage wells to ensure all safety considerations. Groundwater monitoring wells should also be considered for installation in an effort to monitor underground sources of drinking water (USDW).

Recommendation: We recommend the collection and recording of pressure data for all uncemented annuli and injection tubing. Additionally, observation wells should be utilized at all UGS sites, and installation of groundwater monitoring wells to evaluate USDW should be considered.

Inspection, Testing, and Maintenance of Wellheads and Valves (Section 1726.8)

On this topic, the proposed DOGGR regulatory language is fairly adequate, but additional details are lacking and are herein proposed. All wellheads and valves need to be function- and pressure-tested and capable of withstanding the maximum allowable operational pressures in the UGS field.

Recommendation: All wellheads and valving should be function-tested and pressure-tested at least annually, and should be rated to withstanding the maximum allowable operational pressures within the UGS field.

Well Leak Reporting (Section 1726.9)

This subsection of the new UGS regulations requires mandatory reporting of well leaks and provides the definition of what constitutes a "reportable leak." No reporting of other events relating to subsurface and surface incidents or a missed accident is required. The reporting of leaks is adequate for the intended purpose, although the reporting of other events relating to subsurface and surface incidents or a missed accident should be required.

A lot can be learned by the collection and analysis of failures and missed accidents in wellbores, wellheads as well as surface facilities. Data of this kind are often used by a specific industry to improve the safety record and culture overall. In general, the incident doesn't have to necessarily lead to a gas released to highlight a weakness in operating practices or structures.

In order to improve the safety culture across this industry, it is important to implement mandatory record keeping and reporting of all subsurface and above surface integrity issues, near-miss accident scenarios (irrespective of consequences), and any remediation and mitigation actions taken. This reporting, as opposed to the "reportable well leaks," is not as time sensitive and could be integrated into a yearly reporting or as part of the 3-year UGS project review. This information would also, of course, be used directly in the risk assessments.

We also recommend that the division have a periodic review of all reported data and share lessons learned across the industry.

Recommendation: We recommend that a record of mandatory reporting of all integrity issues should be implemented independent of the size of the release. The time line and urgency of the reporting can be varied, depending on the gravity of the release according to the definition in this section of the regulations.

Requirements for Decommissioning (Section 1726.10)

The UGS regulations seem adequate for the decommissioning of a UGS project. However, the regulations do not define or require a pathway to reporting for the plugging and abandoning of a single (or multiple) wellbores.

Historically, a large number of incidents have happened in abandoned wells or fields (Evans, 2009; Folga et al., 2016). It is imperative that all safety precautions be taken prior to abandonment as detection of issues and interventions post abandonment is extremely difficult, costly, and intrusive.

We recommend that language to specify approved abandonment procedures, or to refer to industry standard practices (if deemed adequate), should be added to this section. For example, the abandonment procedure could require assessment of the integrity of the well casing and cement, followed by temporary plugging and abandonment with daily monitoring of annuli pressures for a time of at least a year before final approval to permanently abandon the well is granted. At the least, DOGGR needs to determine whether the current industry standards are adequate.

Recommendation: We recommend that the UGS regulations describe an adequate path to wellbore abandonment. Furthermore, DOGGR needs to determine whether the current industry standards are adequate.

Side bar: Safety Culture

NOTE: The following side bar was contributed by Professor Najmedin Meshkati, a member of the CCST Project's Steering Committee, who was also a member of the "Committee for Analysis of Causes of the Deepwater Horizon Explosion, Fire, and Oil Spill to Identify Measures to Prevent Similar Accidents to the Future," formed by the National Academy of Engineering/National Research Council. The following text is partially adopted from the published report of that same committee, entitled "Macondo Well Deepwater Horizon Blowout: Lessons for Improving Offshore Drilling Safety," (pp. 92-93 of Macondo Well-Deepwater Horizon Blowout: Lessons for Offshore Drilling Safety, National Research Council, 2012) and also updated and augmented by Professor Najmedin.

Although the emphasis in the text of this side bar is on the type of accidents similar to the Macondo Well blowout accident, the overall ideas concerning safety culture are broadly applicable, including to underground gas storage facilities.

The steps taken by the nuclear power and other safety-critical industries to improve system safety are reminiscent of the challenges presently confronting the offshore drilling industry. Although there are significant differences between the oil and gas industry and other industries (as discussed in this chapter), the safety framework and perspectives developed by those other industries can provide useful insights. According to the Swedish Radiation Safety Authority, an organization has good potential for safety when it has developed a safety culture that shows a willingness and an ability to understand risks and manage activities so that safety is taken into account (Oedewald et al., 2011). Other industries, regulatory agencies, trade associations, and professional associations have also addressed safety culture (for example, see Reason, 1998; U.S. NRC 2009; 2011; Nuclear Energy Institute, 2009; CCPS, 2005; IAEA, 1992).

The U.K. Health and Safety Executive defines safety culture as "the product of individual group values, attitudes and perceptions, competencies and patterns of behavior that determine the commitment to, and the style and proficiency of, an organization's health and safety management." Creating safety culture means instilling attitudes and procedures in individuals and organizations ensuring that safety issues are treated as high priority, too. A facility fostering strong safety culture would encourage employees to cultivate a questioning attitude and a rigorous and prudent approach to all aspects of their jobs, and to set up necessary open communication between line workers and middle and upper management (Meshkati, 1999).

A commonly accepted and widely used/cited definition of safety culture was jointly developed through an unprecedented collaboration of the government regulator, United States Nuclear Regulatory Commission (U.S. NRC), and the industry's created self-regulatory body, the Institute of Nuclear Power Operations (INPO). According to this definition, safety culture is "the core values and behaviors resulting from a collective commitment by leaders and individuals to emphasize safety over competing goals to ensure protection of people and the environment" (INPO, Traits of a Healthy Nuclear Safety Culture, INPO 12–012 April 2013).

An effective and healthy safety culture embodies the following generic traits [The traits are adapted from the U.S. Nuclear Regulatory Commission Safety Culture Policy Statement (U.S. NRC, 2011)]:

- Leadership safety values and actions: Safety is treated as a complex and systemic phenomenon. It is also a genuine value that is reflected in the decision-making and daily activities of an organization in managing risks and preventing accidents.

- Personal accountability: All individuals take personal responsibility for safety and contribute to overall safety.

- Problem identification and resolution: Issues potentially affecting safety are readily identified, fully evaluated, and promptly addressed and corrected.

- Work processes: The process of planning and controlling work activities is implemented so that system safety is maintained. The most serious safety issues get the greatest attention.

- Continuous learning: Opportunities to learn about ways to ensure safety are sought out and implemented by organizations and personnel. Hazards, procedures, and job responsibilities are thoroughly understood. Safety culture strives to be flexible and adjustable so that personnel are able to identify and react appropriately to various indications of hazard. These processes and approaches are embedded in management systems and processes that are widely used within the organization.

- Environment for raising concerns: A safety-conscious work environment is maintained, where personnel feel free to raise safety concerns without fear of retaliation, intimidation, harassment, or discrimination. They perceive their reporting as being meaningful to their organizations and thus avoid underreporting.

- Effective safety communication: Communications maintain a focus on safety. Knowledge and experience are shared across organizational boundaries, especially when different companies are involved in various phases of the same project. Knowledge and experience are also shared vertically within an organization.

- Respectful work environment: Trust and respect permeate the organization.

- Questioning attitude: Individuals avoid complacency and continuously challenge existing conditions and activities to identify discrepancies that might result in unsafe conditions. A subordinate does not hesitate to question a supervisor, and a contractor employee does not hesitate to question an employee of an operating company.

[It should be noted that the above definition and traits of healthy safety culture, which have been jointly developed by the U.S. NRC and INPO, have been adopted, almost exactly, by other federal regulatory and safety agencies, e.g., Bureau of Safety and Environmental Enforcement (U.S. BSEE, 2013).]

- Investigations of several large-scale accidents in recent years provide clear illustrations of the consequences of a deficient safety culture. A collision of two trains of the Washington Metropolitan Area Transit Authority (WMATA) Metrorail that occurred in June 2009 resulted in nine deaths and multiple passenger injuries. The National Transportation Safety Board (NTSB) found that WMATA failed to implement many significant attributes of a sound safety program (NTSB 2010).

- The NTSB, which, by quoting Professor James Reason, has called it an "organizational accident," stated that "the accident did not result from the actions of an individual but from the 'accumulation of latent conditions within the maintenance, managerial and organizational spheres' making it an example of a 'quintessential organizational accident'" (NTSB, 2011; Reason, 1998).

- The rupture of the natural gas transmission pipeline that was owned and operated by the Pacific Gas and Electric Company (PG&E), in a residential area in San Bruno, California, on September 9, 2010, is another example of catastrophic "organizational accident" ("Mismanagement Blamed for Bay Area Gas Disaster," *New York Times*, August 30, 2011, by Matthew L. Wald), which has been attributed to the safety culture of the company and lax regulatory oversight, according to the NTSB (2011). PG&E estimated that 47.6 million standard cubic feet of natural gas was released; the released natural gas ignited, resulting in a fire that destroyed 38 homes and damaged 70. Eight people were killed, many were injured, and many more were evacuated from the area.

- Explosions and fires at the BP Texas City Refinery in March 2005 killed 15 people and injured 180 others. The U.S. Chemical Safety and Hazard Investigation Board concluded that the disaster was caused by organizational and safety deficiencies at all levels of the BP Corporation. The U.S. Chemical Safety and Hazard Investigation Board has identified "safety culture" as one of the four "key issues" which caused this accident, along with regulatory oversight, process safety metrics, and human factors (CSB, 2007).

- According to three major seminal reports that investigated the BP Deepwater Horizon (DWH) blowout, inadequate management systems and poor safety culture were major underlying causes of that blowout [Deep Water: The Gulf Oil Disaster and the Future of Offshore Drilling, Report to the President - National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling - January 2011 (2011); the National Research Council's Macondo Well-Deepwater Horizon Blowout: Lessons for Offshore Drilling Safety (2011); and the U.S. Chemical Safety Board (CSB) (June 2016).]

- The American Petroleum Institute (API) Recommended Practice 1173, Pipeline Safety Management System Requirements (First Edition, June 2014, Draft Version 11.2; https://www.pipelinelaw.com/wp-content/uploads/sites/19/2014/09/API-RP-1173.pdf) entire section 10.6 is about "Evaluation of Safety Culture." It recommends that:

- "The pipeline operator shall establish methods to evaluate the safety culture of its organization. Operators shall assess the health of their safety culture using methods that assess employee perception of the safety culture. Methods to assess the perception of the culture include but are not limited to questionnaires, interviews, and focus groups. Policies, operating procedures, continuous vigilance and mindfulness, reporting processes, sharing of lessons learned and employee and contractor engagement support an operator's safety culture. Observations and audits of how each of these are being applied in the daily conduct of operations provide

> indications of the health of an organization's safety culture, including conformance with policies, adherence to operating procedures, practicing vigilance and mindfulness, utilizing reporting processes, integrating lessons learned and engagement of employees and contractors. Failure in application of these provides an indication of potential deterioration of the safety culture. Management shall review the results and findings of perception assessments, observations and audits and define how to improve application of the supporting attributes." (p. 17)

The U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration's (PHMSA) "fully supports the implementation of RP 1173 and plans to promote vigorous conformance to this voluntary standard." Although PHMSA has not yet issued an official safety culture policy statement, it has adopted the Safety Management Systems (SMS) concept and contends that it has been "actively advancing implementation of SMS and a *strong safety culture* within the pipeline and hazardous materials sectors is the next step in continuous safety improvement for America's hazardous materials transportation system." (emphasis added, PHMSA Administrator the Honorable Marie Therese Dominguez's written statement before the U.S. House of Representatives, February 25, 2016).

The American Gas Association (AGA), which is a trade organization representing over 200 natural gas supply companies and others, has also echoed and endorsed the importance of safety culture and its AGA's Safety Culture Statement states, "The AGA and its member companies are committed to promoting positive safety cultures among their employees throughout the natural gas distribution industry" (AGA, 2011).

Most recently, on May 18, 2017, the State of California's Department of Industrial Relations' (DIR) Occupational Safety and Health Standards Board has announced that it has approved adding safety culture as one of new elements to its revamped/updated regulations on refinery safety. [In this regulation, which has been applauded by the industry's trade association, the Western States Petroleum Association (WSPA), and which became effective on October 1, 2017, the "Process Safety Culture," is defined as: "A combination of group values and behaviors that reflects whether there is a collective commitment by leaders and individuals to emphasize process safety over competing goals, in order to ensure protection of people and the environment."] This order is enforced by CalOSHA's Process Safety Management (PSM) Unit, adding section 5189.1 to Title 8 of the California Code of Regulations. This element outlined in the regulation requires refinery employers to: "Understand the attitudes, beliefs, perceptions and values that employees share in relation to safety and evaluate responses to reports of hazards by implementing and maintaining an effective Process Safety Culture Assessment program" (CalOSHA, 2017b).

Side bar: ALARA and ALARP

The acronyms ALARA and ALARP mean “as low as reasonably achievable” and “as low as reasonably practicable,” respectively. While these words seem to be similar, they are not used identically in practice.

The concepts first arose in the field of radiation protection for occupational workers, in which health physicists and nuclear-medicine professionals struggled with how to explain the idea that, although there are strict regulatory limits to the amount of harmful lionizing radiation to which a worker can be exposed, *sometimes meeting those limits is not sufficient*, and *sometimes not meeting them is acceptable.* These concepts were later broadened to apply more generally to other technical areas, such as other fields of health and safety where exposures occur to workers or the general public, or where the release of harmful substances into the environment can cause harm to individuals or other receptors.

The ALARA (as low as reasonably achievable) concept

The U.S. Nuclear Regulatory Commission (U.S. NRC, 2017a) uses the following definition for radiation protection:

As defined in Title 10, Section 20.1003, of the Code of Federal Regulations, ALARA is an acronym for “as low as (is) reasonably achievable,” which means making every reasonable effort to maintain exposures to ionizing radiation as far below the dose limits as practical, consistent with the purpose for which the licensed activity is undertaken, taking into account the state of technology, the economics of improvements in relation to state of technology, the economics of improvements in relation to benefits to the public health and safety, and other societal and socioeconomic considerations, and in relation to utilization of nuclear energy and licensed materials in the public interest.

The National Council on Radiation Protection (NCRP, 1999) explains ALARA this way, again for radiation protection:

In its presentation of dose limitations, the Council set specific upper limits of acceptable dose for occupationally exposed individuals, and the general public, with additional concern for the embryo/fetus. Through the inclusion of the ALARA principle, the NCRP wished to emphasize that adherence only to dose limits was not sufficient. Additionally, the specification in the ALARA principle that economic and social factors be considered has at times been overlooked, resulting in excessive monetary costs with little benefit. The ALARA principle should not be misinterpreted as simply a requirement for dose reductions irrespective of the dose level; sound judgment is essential in its proper application. Nevertheless, even at very low exposure levels, if simple and low-cost means would result in still lower exposures while retaining the beneficial outcome, sound judgment would indicate that such means should be encouraged.

The International Commission on Radiological Protection (ICRP) defines ALARA very succinctly (ICRP, 2007):

ALARA means “as low as readily achievable [with] economic and social considerations being taken into account.”

To paraphrase the ALARA idea, it is not sufficient simply to meet the regulatory limits. Even if these limits are met, one must make “every reasonable effort” to do better, accounting for various factors, of which the most important are usually the state of technology and the costs in relation to the benefits. *In sum, broadly speaking, the ALARA concept comes into play when the regulations have already been met but when doing better is feasible.*

The ALARP (as low as reasonably practicable) concept

The ALARP concept is similar, but in practice it is usually brought into play when it is difficult to meet the strict regulatory limits.

The UK Health and Safety at Work Act (UK HSE, 1974; 2009) explains this idea as follows. Note that this explanation is not limited to radiation exposures:

ALARP stands for “as low as reasonably practicable,” and is a term often used in the regulation and management of safety-critical and safety-involved systems. The ALARP principle is that the residual risk shall be reduced as far as reasonably practicable. … For a risk to be ALARP, it must be possible to demonstrate *that the cost involved in reducing the risk further would be grossly disproportionate to the benefit gained. The ALARP principle arises from the fact that infinite time, effort and money could be spent in the attempt of reducing a risk to zero. It should not be understood as simply a quantitative measure of benefit against detriment. It is more a best common practice of judgment of the balance of risk and societal benefit.*

To paraphrase the idea, ALARP is often brought into play when a regulatory limit has not been met, but the cost of doing so “would be grossly disproportionate to the benefit gained.” That is, at a certain point a judgment is made that meeting the limits is not “reasonably practicable,” accounting for various factors, of which the most important are usually the state of technology and the costs in relation to the benefits. *In sum, broadly speaking, the ALARP concept comes into play when the regulations cannot be met in a “reasonably practicable” way because the benefits to be gained from doing so are disproportionately larger than the costs required.*

1.7 RISK-RELATED CHARACTERISTICS OF UGS SITES IN CALIFORNIA

1.7.1 Integrative Table

In the previous six sections of this report, we have reviewed the state of UGS in California from the perspective of the risk posed by UGS to health, safety, the environment, and UGS infrastructure itself, and we presented discussion of managing and mitigating these risks. To summarize the detailed discussion and analysis of this chapter, we provide here a summary as shown in Table 1.7-1 that allows readers to see at a glance some the most salient characteristics of UGS sites in California related to the various aspects of UGS risk.

The rows in Table 1.7-1 comprise descriptive attributes, specific hazard categories, health- and exposure-related aspects, and GHG emission categories. The columns of the table list the 13 California UGS facilities organized by ownership, with the independent facilities listed first, the northern California utility-owned facilities listed second, and the southern California facilities listed third.

Where appropriate, we made a judgment about the qualitative relative level of risk associated with each value or descriptor in the table, as shown by the shading of the color. Specifically, darker shades generally correspond to larger expected hazard, while lighter shades correspond to less expected hazard from that attribute. We emphasize that this qualitative assessment is independent of (i.e., does not take into account) any and all risk mitigation actions that may have been implemented at the sites. In addition, the storage capacity attribute can be seen as both a risk-related characteristic—more mass available to leak in a blowout—or a benefit—more capacity to store gas. But we assign larger-capacity facilities darker shadings because the table is on risk-related characteristics only, not on benefits. Furthermore, the qualitative comparative assessments made possible by the information in Table 1.7-1 in no way take the place of the QRA recommended previously in Section 1.6 for each facility. Instead, Table 1.7-1 is useful for comparing UGS sites qualitatively across all facilities in California. Finally, we note that the Montebello facility was officially closed December 31, 2016, following extensive surface leakage of natural gas over decades; it is included in Table 1.7-1 because it apparently operated for some periods during our 10-year study period January 1, 2006 to December 31, 2015.

1.7.2 Example Uses of Table

As an example of one particular risk scenario, an initiating event for a large-scale LOC event might be well integrity failure by corrosion or sand erosion of steel pipe or casing. Both of these are more likely to become problems for older and repurposed wells. Therefore, age of wells is a relevant attribute. From the UGS Characteristics section of the table, we note that the median spud date of wells active in 2015 for the Playa del Rey, La Goleta, and Aliso Canyon facilities are all from before the mid-1950’s, and for Playa del Rey, the median spud date year is 1935.

Other initiating events that could rupture a well or flowline leading to significant LOC are landslides and earthquakes, especially those that may cause slip on faults intersected by wells. A glance at the table in the Failure Modes section shows that Aliso Canyon and Honor Rancho have relatively high landslide hazard, while Aliso Canyon, Honor Rancho, La Goleta, and Montebello all have relatively high seismic hazard. Wildfire is another hazard that could impact surface infrastructure and its ability to contain high-pressure gas. Table 1.7-1 also shows that Aliso Canyon, Honor Rancho, and Playa del Rey all have very high wildfire hazard.

Regarding the likelihood side of this high-level comparative risk example, we note that Aliso Canyon, Montebello, and Playa del Rey have a history of multiple recorded LOC incidents, while Honor Rancho has one recorded incident. The table also shows that McDonald Island has two recorded incidents of significant LOC, and there have been reports of recent surface gas leakage not yet included in publications.

Finally, as we turn now to consider potential consequences of large-scale LOC incidents, the Health and safety section of Table 1.7-1 shows very low populations surrounding most of the UGS facilities in California, with notable exceptions at Montebello, Playa del Rey, Aliso Canyon, Los Medanos, and Honor Rancho. The implication is that larger numbers of people could be impacted by LOC incidents from these five facilities relative to comparable releases from the other facilities.

What emerges from the above example of high-level qualitative comparative risk assessment of the UGS facilities in California is that Playa del Rey stands out as a facility with relatively higher risk to health and safety than the other facilities in California. Aliso Canyon, Honor Rancho, and La Goleta also present health and safety risk higher than other facilities, in part because of their location near large numbers of people. Los Medanos is also near significant population and has recorded LOC incidents, but its wildfire and landslide hazard are only moderate. We note again that Table 1.7-1 presents many qualitative attributes that in the near future can be further quantified based on the risk management plans that each facility is now required to develop according to DOGGR's emergency and draft regulations, along with the quantitative risk assessment (QRA) recommended in this report (see Section 1.6).

1.7.3 Conclusions for site-specific hazard and risk assessment

Finding: The hazards, vulnerabilities, and risk levels are generally different for facilities that store gas in former gas reservoirs versus former oil reservoirs, and also differ qualitatively among individual facilities based on their unique characteristics. Identification of such differences allows the high-level or preliminary assessment of which UGS sites in California may present higher risk to health, safety, and the environment than others, overall or for certain risk categories and scenarios. High-level identification of such risk-related differences can lead to more specialized and effective risk management and mitigation approaches for each setting.

Conclusion: Qualitative assessment of risk-related characteristics of California UGS facilities points to relatively larger potential risk in facilities that have older repurposed wells often in former oil reservoirs, are located in hazard zones for seismic or other natural disaster risks, may have a higher rate of LOC incidents, and are located near large population centers. (See Conclusion 1.25a in Executive Summary.)

Conclusion: Of the currently operating facilities, Playa del Rey stands out as a facility with risk-related characteristics with high concern for health and safety relative to the other facilities in California, followed by Aliso Canyon, Honor Rancho, La Goleta and Los Medanos. (See Conclusion 1.25b in Executive Summary.)

The qualitative risk-related information in Table 1.7-1, and in the near future more quantitative risk assessments of each facility, can be used by decision-makers to examine the tradeoffs between potential hazards and risks associated with facilities and their importance in meeting the demands of the natural gas supply. This can and should be done facility by facility: For example, the Aliso Canyon facility according to Table 1.7-1 is at relatively higher risk because of certain attributes and the nearby population, but it also has important benefits because of its large gas storage capacity. In contrast, Playa del Rey has record of LOC incidents, is near a large population center, features tsunami and wildfire threats, and has a relatively small gas storage capacity. While the high-level and qualitative comparative risk assessment described here provides important information for assessing long-term viability, it is only one-half of the equation. In particular, the assessment here only looks at the facility-specific risks of UGS without looking at the facility-specific benefits of UGS.

Recommendation: The State of California should conduct a comparative study of all UGS facilities to better understand the risk of individual facilities relative to others. This comparative study should be based on the risk management plans being developed for each facility and should be commissioned when such risk management plans have matured to the point that they comprise formal risk assessments and mitigation plans (e.g., in five years). The end product would be a table similar to Table 1, but the revised table would be based on quantitative rather than qualitative information. The quantitative risk-related information on each facility can then be used by decision makers to examine the tradeoffs between risks associated with individual facilities and their importance in meeting the demands of the natural gas supply. (See Recommendation 1.25 in Executive Summary.)

Table 1.7-1. Comparative risk-related characteristics for California UGS facilities (layout of this table is for size 11"x 17" paper). Darker shades generally correspond to larger values or larger expected hazard while lighter shades correspond to less expected hazard from that attribute.

Facility[1]		Independents: Gill Ranch Gas	Independents: Kirby Hill Gas	Independents: Lodi Gas	Independents: Princeton Gas	Independents: Wild Goose Gas	Pacific Gas and Electric: Los Medanos Gas	Pacific Gas and Electric: McDonald Island Gas	Pacific Gas and Electric: Pleasant Creek Gas	Southern California Gas: Aliso Canyon	Southern California Gas: Honor Rancho	Southern California Gas: La Goleta Gas	Southern California Gas: Montebello	Southern California Gas: Playa del Rey	Hazard highlighting ranges and categories (NA = not applicable or available): Lowest	Low	Medium	High	Highest
1.1 UGS Characteristics																			
Nearest incorporated city or cities		Mendota	Fairfield	Lodi & Galt	Willows	Gridley	Concord	Stockton	Winters	Los Angeles	Santa Clarita	Santa Barbara & Goleta	Montebello	Los Angeles					
County or counties (if a second county is listed, it only contains a portion of the connection line)		Madera & Fresno	Solano	San Joaquin & Sacramento	Colusa	Butte	Contra Costa	San Joaquin & Contra Costa	Yolo	Los Angeles	Los Angeles	Santa Barbara	Los Angeles	Los Angeles					
Owner/operator		Gill Ranch LLC (75%), PG&E (25%)	Rockpoint	Rockpoint	AGL (through Pivotal Energy Development)	Rockpoint	PG&E	PG&E	PG&E	SoCalGas	SoCalGas	SoCalGas	SoCalGas	SoCalGas					
Average depth (range) of storage reservoir(s) (ft)		5,850 - 6,216	1,550 - 5,400	2,280 - 2,515	2,170	2,400 - 2,900	4,000	5,220	2,800	9,000	10,000	3,950	7,650	6,200	1,550 - 3,000	3,000 - <6,000	6,000 - <8,000	8,000 - 10,000	
Starting year		2010	2006	2001	2012	1998	1976	1962	1962	1973	1975	1942	1956	1942	2005 - 2012	1985 - 2004	1965 - 1984	1942 - 1964	
Capacity (Bcf)	2006	0.0	5.0	17.0	0.0	20.5	17.4	82.0	2.3	82.0	23.0	21.5	NA	2.6	2.3 - <3.0	3.0 - <10.0	10.0 - <30.0	30.0 - 82.0	
	2015	20.0	15.0	17.0	11.0	75.0	17.9	82.0	2.3	86.2	27.0	19.7	NA	2.4				30.0 - 86.2	
Average % capacity utilized annually - 2006 to 2015		35%	70%	128%	47%	50%	57%	45%	55%	69%	108%	56%	NA	159%	35% - <50%	50% - <80%	80% - <110%	110% - 159%	
Median tubing pressure per pool (psi; % of initial)		2,322 (89%) 2,399 (86%)	1,019 (89%) 1,560 (71%)	846 (86%) 931 (85%)	1,080 (106%)	1,251 (96%)	1,390 (79%)	1,850 (79%)	1,206 (95%)	2,280 (63%)	2,730 (61%)	1,676 (87%)	63 (initial pressure NA)	1,370 (50%)	63 - <1,300	1,300 - <1,700	1,700 - <2,100	2,100 - 2,730	
Average annual gas transfer per well per month gas was transferred from 2006 to 2015 (million scf)		150	69	511	78	866	255	75	22	197	244	232	NA	13	13 - <20	20 - <100	100 - <500	500 - 866	
Wells connected to storage reservoir open[2] in 2015	Number: Transferred gas during study period	12	18	17	8	17	21	81	7	111	38	17	20	34		7 - 9	10 - 25	25 - 74	75 - 111
	Number: Did not transfer gas during study period	0	0	9	5	0	0	7	0	4	3	1	0	20	0	1 - 9	10 - 20		
	Age: Oldest (yrs)	5	40	72	61	16	41	78	66	75	59	85	x	84	5 - 24	25 - 49	50 - 74	75 - 85	
	Age: Median (yrs)	5	7	13	4	7	36	41	41	42	39	63	x	79	4 - 24	25 - 49	50 - 74	75 -79	
Estimated number of groundwater wells to 2015 capacity (/Bcf)	Public and domestic	0.1	0.1	9.2	0.9	0.0	0.5	0.1	1.7	0.0	0.0	0.4	x	0.0	0.0 - 1.0	1.0 - <3.0	3.0 - <6.0	6.0 - 9.2	
	Total	1.4	1.2	11.6	3.4	0.0	1.7	1.1	5.4	0.0	0.3	2.9	x	5.0				6.0 - 11.6	
Depth of the base of fresh water (ft)	Maximum	950	1,850	2,485	1,870	1,000	2,140	100	2,270	Not available	Not available	None	x	800	NA	100 - <1,000	1,000 - <2,000	2,000 - 2,485	
	Above minimum storage pool depth	4,900	-300	-205	300	1,400	1,860	5,120	530			Not applicable	x	5,400	5,400 - >2,000	2,000 - >1,000	1,000 - >0	0 - -300	
Max. perf. depth of public, domestic, or irrigation well (ft)	(ft)	510	195	693	400	Not available	320	290	870	No wells	145	1,270	x	No wells	NA	145 - <400	400 - <800	800 - 1,270	
	% of max. fresh water	51%	11%	24%	21%		15%	290%	36%		Not calculable	Infinite	x		11% - <25%	25% - <50%	50% - 75%	>75% - 290%	
% of public, domestic, and irrigation wells with BPI depth		100%	56%	47%	42%	0%	69%	56%	94%		75%	95%	x		NA and 100%	<100% - 80%	<80% - 60%	<60% - 42%	0%
CASGEM basin prioritization[3]		High	Very Low	High	Medium	Medium	None	Medium	High	Medium	Medium	None	x	Medium	None	Very Low	Medium	High	

[1]Storage in facilities whose name includes "Gas" is in depleted gas reservoirs; otherwise storage is in depleted oil reservoirs

[2]"open" includes wells with DOGGR status "Active" and "Idle", which are unplugged and have a wellhead

[3]CASGEM = California Statewide Groundwater Elevation Monitoring

x - data not collected because Montebello is not operating as of 2017

Facility[1]		Independents					Pacific Gas and Electric			Southern California Gas					Hazard highlighting ranges and categories (NA = not applicable or available)				
		Gill Ranch Gas	Kirby Hill Gas	Lodi Gas	Princeton Gas	Wild Goose Gas	Los Medanos Gas	McDonald Island Gas	Pleasant Creek Gas	Aliso Canyon	Honor Rancho	La Goleta Gas	Montebello	Playa del Rey	Lowest	Low	Medium	High	Highest
1.2 Failure modes and likelihoods and hazards																			
Maximum deep-seated landslide susceptibility	Well(s) and field line(s)	0	VI	0	0	0	VI	0	VII	X	X	X	V	X	(0)	(V)	(VI) - (VIII)	(IX) - (X)	
	Connection line	0	VII	0	0	0	III	0	V	X	X	0	VII	X					
Last fault rupture through or (*) within 500 m of field line(s) (yrs ago)		None	<130,000	None	None	None	<130,000*	None	None	<15,000*	<15,000*	<130,000*	None	None	None	<130,000*	<130,000 - <15,000*	<15,000	
Hazard of Quaternary fault shearing of well(s) present		No	Yes	No	No	No	Maybe	No	No	Yes	Unlikely	Unlikely	No	No	No	Unlikely	Maybe	Yes	
Maximum 2% probability of exceeding 0.2-sec spectral acceleration in 50 years (g)	Well(s)	0.85	1.55	0.65	0.75	0.65	2.15	1.15	1.75	2.55	2.45	2.65	2.15	1.65		0.65 - <1.00	1.00 - <2.00	2.00 - 2.75	
	Field line(s)	0.85	1.55	0.65	0.75	0.65	2.15	1.15	1.85	2.55	2.45	2.65	2.15	1.65					
	Plant	0.85	1.55	0.65	0.75	0.65	2.15	1.15	1.85	2.55	2.45	2.65	2.15	1.55					
	Connection line	1.45	1.55	1.25	0.95	0.65	2.15	1.25	1.85	2.75	2.45	2.65	2.15	1.55					
Maximum 2% probability of exceeding 1-sec spectral acceleration in 50 years (g)	Well(s)	0.45	0.55	0.35	0.45	0.45	0.85	0.75	0.85	1.45	1.15	1.55	1.05	0.95		0.35 - <0.50	0.50 - <1.00	1.00 - <1.50	1.50 - 1.55
	Field line(s)	0.45	0.55	0.35	0.45	0.45	0.85	0.75	0.85	1.45	1.15	1.55	1.05	0.95					
	Plant	0.45	0.55	0.35	0.45	0.35	0.75	0.75	0.75	1.45	1.05	1.45	1.05	0.85		0.35 - <0.50	0.50 - <1.00	1.00 - 1.45	
	Connection line	0.75	0.75	0.85	0.55	0.45	0.75	0.85	0.75	1.45	1.05	1.45	1.05	0.95					
Liquefaction hazard zone	Well(s) and field line(s)	? (unmapped, but on alluvium by river)	? (unmapped, but includes alluvium by	? (unmapped, but includes alluvium near	? (unmapped, but includes alluvium by	? (unmapped, but includes alluvium by	No (unmapped, but no alluvium or shallow	? (unmapped, but includes alluvium near slough)	? (unmapped, but includes alluvium by river)	No	Yes	? (unmapped, but includes alluvium by	No	Yes	No		?	Yes	
	Plant									No	Yes		No	Yes					
	Connection line									Yes	Yes		No	Yes					
Earthquake-induced landslide hazard zone	Well(s) and field line(s)	No (unmapped, but little topographic relief)	? (unmapped, but includes slopes)	No (unmapped, but little topographic relief)	No (unmapped, but little topographic relief)	No (unmapped, but little topographic relief)	? (unmapped, but includes slopes)	No (unmapped, but little topographic relief)	No (unmapped, but little topographic relief)	Yes	Yes	? (unmapped, but includes bluffs	No	Yes					
	Plant									No	No		No	Yes					
	Connection line									Yes	No		No	No					
Tsunami hazard	Well(s)	No	No	No	No	No	No	No	No	No	No	Yes	No	? (three observation wells assigned to the Del Rey Hills Area even though they are in the Venice Beach Area)					
	Field line(s)	No	No	No	No	No	No	No	No	No	No	Yes	No	No	No			Yes	
	Plant	No	No	No	No	No	No	No	No	No	No	No	No	No					
	Connection line	No	No	No	No	No	No	No	No	No	No	No	No	No					
Flooding hazard	Well(s) and field line(s)	No	No	No	No	Yes	No	Yes	No	No	No	Yes	No	No					
	Plant	No	No	No	Yes	No	No	Yes	No	No	No	No	No	No					
	Connection line	Yes	Yes	Yes	Yes	Yes	No	Yes	No	No	No	No	No	No					
Fire hazard severity zones - predominant (maximum, if different)	Well(s)	Not zoned	Moderate	Not zoned	Not zoned	Not zoned	Moderate	Moderate	Moderate	Very high	Very high	Not zoned	Not zoned	Very high	Not zoned		Moderate		Very high
	Field line(s)	Not Zoned	Moderate	Not zoned (moderate)	Not zoned	Not zoned (moderate)	Moderate	Moderate	Moderate	Very high	Very high	Not zoned	Not zoned	Very high					
	Plant	Not Zoned	Moderate	Not zoned	Not zoned	Not zoned	Moderate	Not zoned	Moderate	Very high	Very high	Not zoned	Not zoned	Very high					
	Connection line	Not zoned (moderate)	Moderate	Not zoned (moderate)	Not zoned (moderate)	Not zoned (moderate)	Moderate	Not zoned (moderate)	Moderate	Very high	Very high	Not zoned	Not zoned	Not zoned (very high)					
Number of reported distinct LOC incidents in Evans (2008) and in Folga et al. (2016)		0	0	0	0	1	1	2	1	3	1	0	1 (continuous surface leakage for years)	3					
1.4 Health and safety																			
C/Q distances (meters)		9,124	9,813	7,977	9,686	9,102	9,743	9,282	9,553	9,116	8,998	8,608	12,037	9,506					
Proximity of handling plant (center) to well field (km)		0	0.7	6.5	0.9	8	0.3	0	0.4	0.2	0	0.5	x	0		8 - 6.5	0.9 - >0	0	
Population and sensitive receptors in proximity to UGS (QL50: 50th percentile of C/Q)																			
Total population		909	401	23,771	848	195	223,069	6,473	8,821	325,330	180,359	101,371	1,594,128	691,757	195 - 999	1,000 - 9,999	10,000 - 99,999	100,000 - 999,999	1,000,000 - 1,600,000
Children under 5		82	17	1,600	41	9	15,640	388	545	18,711	11,139	4,040	113,206	39,352	9 - 99	100 - 999	1,000 - 9,999	10,000 - 99,999	100,000 - 120,000
Daycare centers		0	0	10	0	0	176	2	9	244	121	77	877	577	0	1 - 5	6 - 50	51 - 500	>500 - 880
Schools		0	0	9	2	0	63	0	4	102	54	32	482	218			6 - 25	26-125	126 - 482
Elderly care facilities		0	0	2	0	0	92	0	0	130	61	41	59	85					126 - 130
Hospitals		0	0	0	0	0	3	0	0	4	1	3	26	9		1 - 2	3 - 6	6 - 18	19 - 26
Median (max) formaldehyde emissions from 1996 - 2015, predominantly from compressors during routine operations (lbs/yr)		4 (5)	108 (205)	1,291 (1,291)	not reported	not reported	4,968 (7,204)	11,163 (11,163)	not reported	15,001 (20,640)	18,675 (27,296)	2,197 (3,456)	1 (19,242)	3,038 (5,772)	1 - <100	100 - <1,000	1,000 <10,000	10,000 - 18,675	
1.5 GHG emissions																			
Average observed methane emission rate (kg CH4/hr)		88	37	0	43	35	11	150	16	200[3]	740	36	NA	0	NA or 0	11 - <30	30 - <90	90 - <270	270 - 740
Extrapolated annual emissions/average annual gas injection (%)		0.8	0.4	0	0.4	0.1	0.1	0.2	0.4	0.2[3]	1.2	0.1	NA	0	NA or 0	>0 - 0.3	>0.1 - 0.6	>0.3 - 0.9	>0.9 - 1.2

[3]Aliso emissions measured following repair of the 2015 blowout

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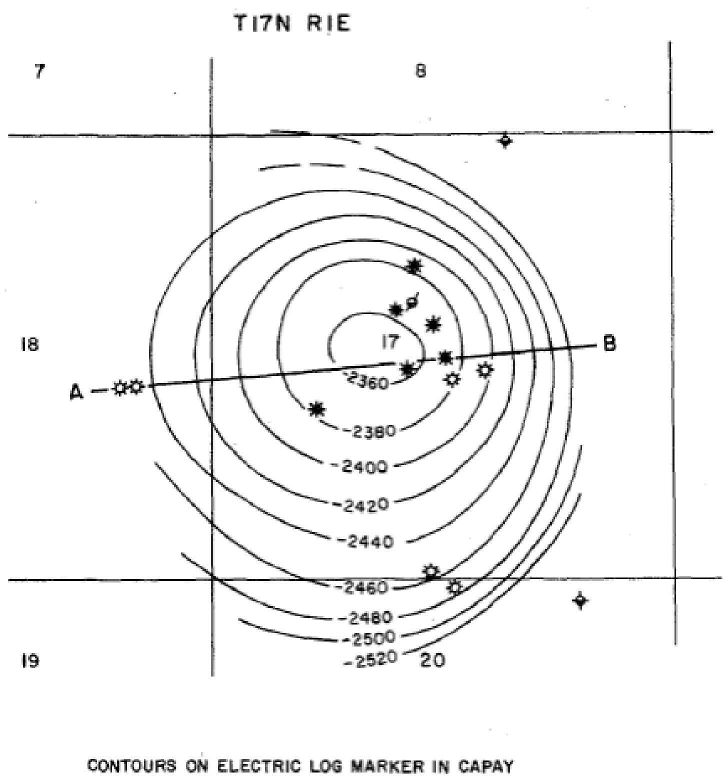
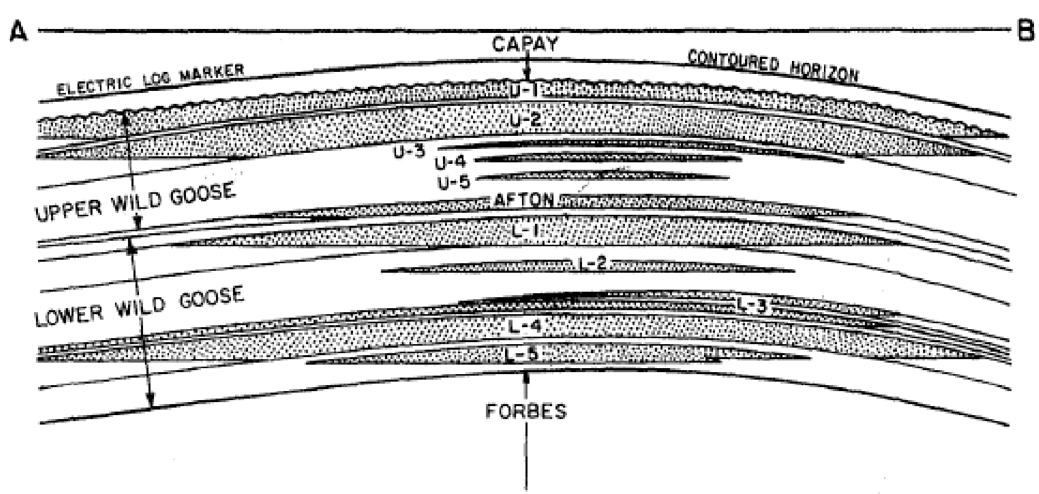
Appendix 1.A. California gas storage and geologic trap type

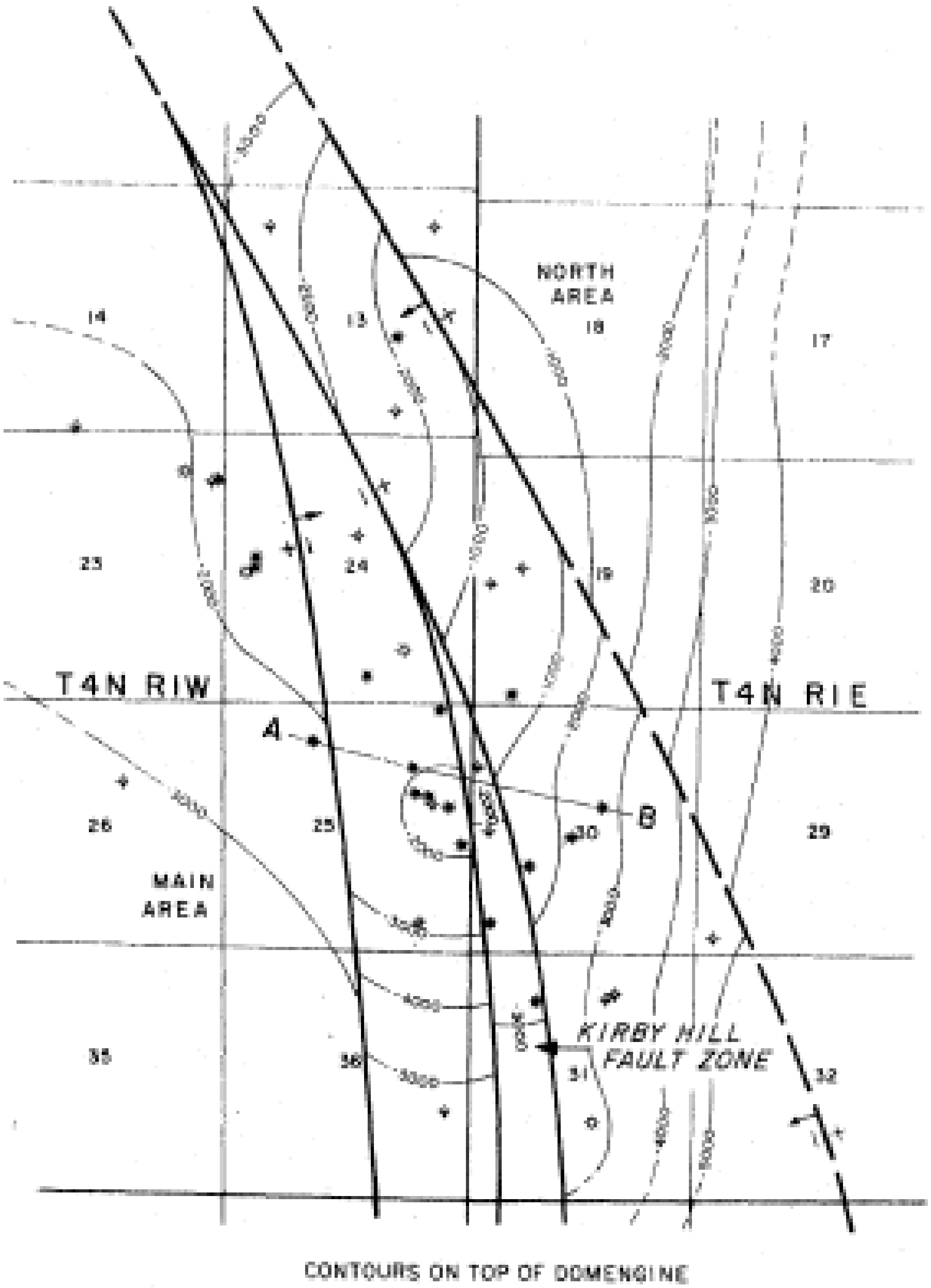
As mentioned in Section 1.1.5 and listed in Table 1.1.3, gas is stored underground in three different types of geologic traps in California. Figure 1A-1 provides an example of each type.



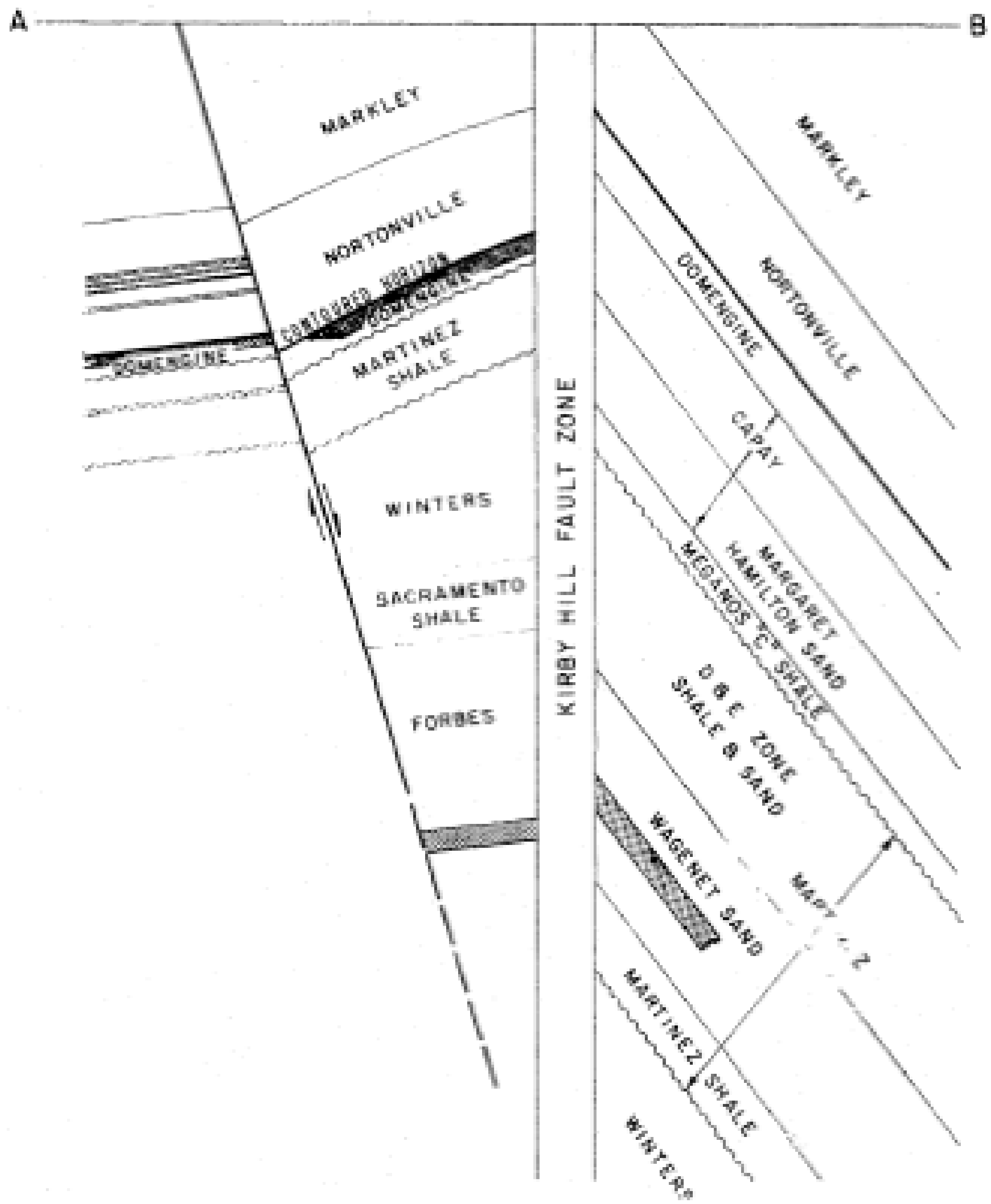
(a)



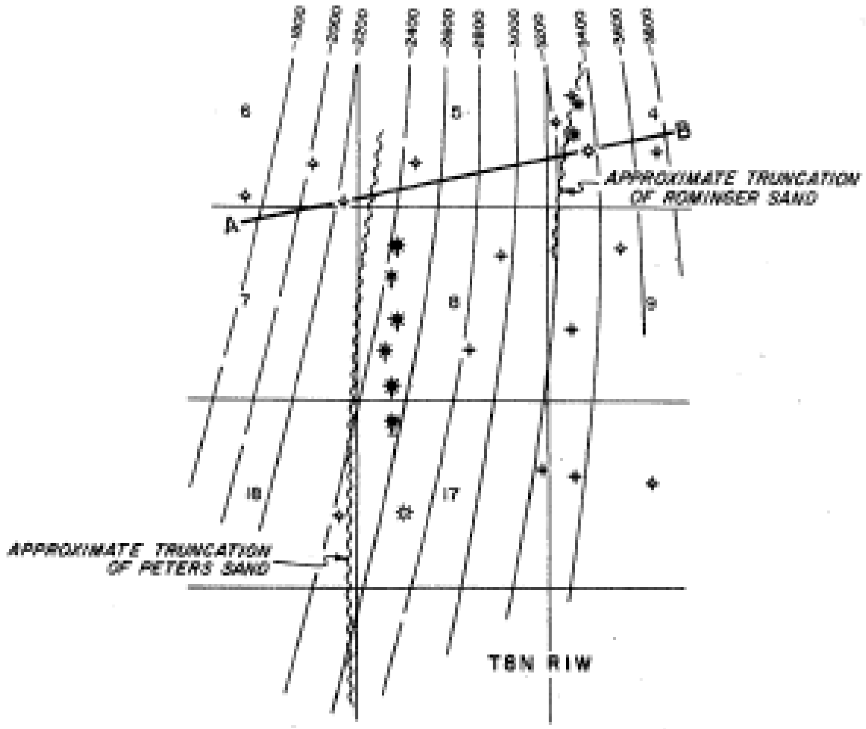
(b)


NORTH AREA
T4N R1W
T4N R1E
MAIN AREA
KIRBY HILL FAULT ZONE
A
B
14
13
18
17
23
24
19
20
26
25
30
29
35
36
31
32
CONTOURS ON TOP OF DOMENGINE

(c)

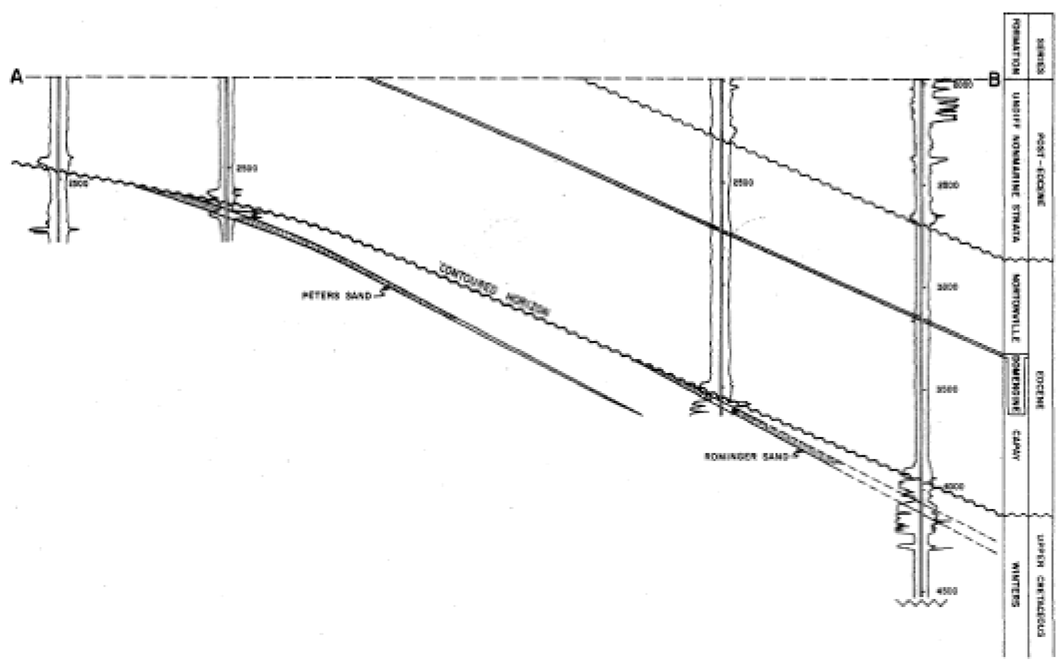

A
B
MARKLEY
NORTONVILLE
CONTORTED HORIZON
DOMENGINE
MARTINEZ
SHALE
WINTERS
SACRAMENTO
SHALE
FORBES
KIRBY HILL FAULT ZONE
MARKLEY
NORTONVILLE
DOMENGINE
CAPAY
MARGARET
HAMILTON SAND
MEGANOS "C" SHALE
D B E ZONE
SHALE & SAND
WAGENET SAND
MARTINEZ SHALE

(d)



CONTOURS ON TOP OF WINTERS

(e)



(f)

Figure 1.A-1. Macroscopic trap types: (a) structure contour of and (b) cross section through the Wild Goose Gas field's structural trap, (c) structure contour of and (d) cross section through the Kirby Hill Gas field's fault trap, (e) structure contour of and (f) cross section through the Pleasant Creek Gas field stratigraphic trap. Structure contour maps are akin to topographic maps. Instead of ground surface contours however, they show contours of a contact between geologic materials in the subsurface, such as between the top of a sandstone reservoir and the overlying caprock. Dots and circles on the maps represent well locations. Lettered lines on the maps are the location and orientation of the cross section subsequent to each map. Unlettered lines on the maps indicate section boundaries with each section number indicated within. Remaining lines are generally geologic features, consisting of faults in (c) and geologic unit edges in (e).

Structural traps are created by folding of the reservoir and caprock into an inverted bowl of some shape. Gas and oil are buoyant relative to the water that otherwise occupies the pore space in the rocks, and consequently rises into the structure, from whence all or some of it is unable to escape through the caprock. Various processes can fold the reservoir and caprock, such as lateral shortening due to tectonic compression (convergence between tectonic plates) and differential consolidation of sediments as they are buried by additional deposition.

Fault traps are created by tilting of a reservoir and caprock, and faulting through the reservoir and caprock that creates a seal. Faulting can create this seal through a few mechanisms. It can cause caprock to be juxtaposed against reservoir rock. It can smear caprock across reservoir rock. It breaks reservoir rock constituents into finer particles with smaller pores between them.

Stratigraphic traps consist of the reservoir rock transitioning to a caprock along its length. This can occur during initial deposition, such as sand deposited against a sloping surface of bedrock with low permeability. Lateral stratigraphic transition can also occur due to erosion of a portion of the reservoir rock subsequent to deposition followed by deposition of a caprock.

More than one of these macroscopic trap types can occur in a single reservoir/pool, as indicated on Table 1.1-3. For instance, a structural trap can be offset and sealed by a fault, trapping gas and oil on only one side of the fault for a variety of reasons. The fault zone might have sufficiently large pores on one side to allow gas or oil to escape. Or gas and oil might have migrated into the structure from only one direction.

Appendix 1.B. Dispersion modeling

1.B.1 Overview

In this section, we provide additional details on the meteorological modeling, data, and assessment results that was summarized in Section 1.4 of Chapter 1. Some of the material provided in Section 1.4 is repeated here in the interest of continuity.

Methodology

Gaussian Plume Dispersion Model

Standard approaches to analyze emissions of toxic air pollutants to community-scale concentrations are based on Gaussian plume dispersion models. The origin of the Gaussian model is found in work by Sutton (1932), Pasquill (1961; 1974), and Gifford (1961; 1968). The standard model considers a continuous source of strength Q (in mass per second) at effective height (h) above the ground. With an assumed uniform wind speed (u), the model provides concentration C (in mass per cubic meter) using the formula:

$$\frac{C}{Q}(x,y,z) = \frac{1}{2\pi\sigma_y\sigma_z u} e^{-y^2/2\sigma_y^2}\left[e^{-(z-h)^2/2\sigma_z^2} + e^{-(z+h)^2/2\sigma_z^2}\right]$$

In this expression, x is radial distance downwind from the emissions. The coordinate y refers to horizontal direction at right angles to the plume axis with y equal to zero on the x axis. The coordinate z is height above ground, which for the time being is assumed to be flat and uniform. The parameters σ_y and σ_z are standard deviations of the distribution C in the y- and z-directions, respectively. The purpose of the last term is to account for reflection of the plume at the ground by assuming an image source at distance h beneath the ground surface.

The dispersion parameters σ_y and σ_z are given as functions of downwind distance (x) and stability, and are based on a combination of experimental results and theory. The most widely used scheme was developed by Pasquill (1961) and modified slightly by Turner (1967). Table 1.B-1 and 1.B-2 list the criteria for Pasquill's six stability classes, which are based on five classes of surface wind speeds, three classes of daytime incoming solar radiation, and two classes of nighttime cloudiness. In general, stability classes A through C represent unstable conditions, class D represents nearly neutral conditions, and classes E and F represent stable conditions.

Table 1.B-1. Dispersion Parameters for the plume model (Briggs, 1973).

	σ_y				σ_z		
Pasquill type	**a**	**b**	**c**		**a**	**b**	**c**
Open-Country Conditions							
A	0.22	0.0001	-1/2		0.20	0	1
B	0.16	0.0001	-1/2		0.12	0	1
C	0.11	0.0001	-1/2		0.08	0.0002	-1/2
D	0.08	0.0001	-1/2		0.06	0.0015	-1/2
E	0.06	0.0001	-1/2		0.03	0.0003	-1
F	0.04	0.0001	-1/2		0.016	0.0003	-1
Urban Conditions							
A-B	0.32	0.0004	-1/2		0.24	0.001	1/2
C	0.22	0.0004	-1/2		0.2	0	1
D	0.16	0.0004	-1/2		0.14	0.0003	-1/2
E-F	0.11	0.0004	-1/2		0.08	0.00015	-1/2

Table 1.B-2. Meteorological conditions defining Pasquill Stability Classes.

Surface wind speed (m/s)	**Daytime Incoming Solar Radiation**			**Nighttime Cloudiness**	
	Strong	**Moderate**	**Slight**	**> 4/8**	**≤ 3/8**
<2	A	A-B	B	E	F
2 - 3	A-B	B	C	E	F
3 - 5	B	B-C	C	D	E
5 - 6	C	C-D	D	D	D
>6	C	D	D	D	D

By using wind speed, wind direction, shortwave incoming radiation and cloud cover, the Gaussian plume model was run for each facility for a one-year period, 08/15/2015–08/15/2016, for each hour in a domain with a radius of 10 km centered on the source and a spatial resolution of 100 m. Wind speeds below 0.5 m/s were assumed to be 0.5 m/s.

Due to the lack of emission data, the source term was set at 1 ug s^{-1} and was assumed to constant in time for the entire period. This selection is intended for posterior calculation of the "concentration over flux" ratio (C/Q) and to facilitate the exposure assessment relative to the source term. The source height was selected to be 3 m above ground to account for the initial mixing due to turbulent fluxes that may occur at the source level, and the concentration plane was 2 m. In order to account for the spatial distribution of the source, all the active wells within a storage facility were considered as a point source with the same characteristics (height and strength). The resulting concentration field was then normalized to the number of wells, to keep the total source strength equal to 1 ug s^{-1}

Storage facilities

Table 1.B-3 shows the 13 underground storage facilities considered in this work, along with the location, capacity, reservoir type, area, and number of active wells.

Table 1.B-3. Underground Gas Storage Facilities.

Storage Facility	Latitude, Longitude	Capacity (Bcf)	Reservoir type	Field Area (km²)	Active Wells	County
Aliso Canyon	34.313, -118.558	86.2	Oil	13.75	141	Los Angeles
Gill Ranch Gas	36.793, -120.250	20.0	Gas	25.90	26	Madera
Honor Rancho	34.456, -118.598	27.0	Oil	9.27	51	Los Angeles
Kirby Hill Gas	38.169, -121.918	15.0	Gas	17.15	23	Solano
La Goleta Gas	34.421, -119.826	19.7	Gas	4.95	19	Santa Barbara
Lodi Gas	38.201, -121.208	17.0	Gas	19.50	24	San Joaquin
Los Medanos Gas	38.027, -122.021	17.95	Gas	18.18	23	Contra Costa
McDonald Island Gas	37.994, -121.480	82.0	Gas	46.75	88	San Joaquin
Montebello	34.025, -118.094	---	Oil	15.07	211	Los Angeles
Playa del Rey	33.970, -118.446	2.4	Oil	7.46	49	Los Angeles
Pleasant Creek Gas	38.553, -122.000	2.25	Gas	11.91	7	Yolo
Princeton Gas	39.390, -122.020	11.0	Gas	9.97	13	Colusa
Wild Goose Gas	39.323, -121.890	75.0	Gas	6.53	21	Butte

Meteorological Data

Integrated Surface Database

NOAA's Integrated Surface Database (ISD) provides meteorological data; however, the distances between California UGS sites and the closest stations can range from 2 to 25 km. Many UGS facilities are located in an area of complex topography, which can make the available meteorological data unreliable.

ISD consists of global hourly and synoptic observations from more than 100 original data sources that collectively archived hundreds of meteorological variables. It is compiled by the NOAA's National Climatic Data Center (NCDC) and accessible through the website https://www.ncdc.noaa.gov/isd. The primary data sources include the Automated Surface Observing System (ASOS), Automated Weather Observing System (AWOS), Synoptic, Airways, METAR, Coastal Marine (CMAN), Buoy, and various others, from both military and civilian stations, including both automated and manual observations (Smith et al., 2011). ISD contains over 2 billion surface weather observations from more than 34,000 stations worldwide included in the archive (1900–present). Currently, there are more than 14,000 active stations that are updated daily in the database. ISD contains 54 quality control (QC) algorithms, which serve to process each data observation through a series of validity checks, extreme value checks, internal (within observation) consistency checks, and external (versus another observation for the same station) continuity checks. This QC is conservative in that it was designed to eliminate obvious errors in the data, minimize over-flagging of data, and ensure to the greatest extent possible that valid values were not removed or flagged as erroneous.

Table 1.B-4 shows the locations of the underground storage facilities as well as the ISD station closest to these facilities. In Table 1.B-4, the two closest ISD stations to each underground storage facilities, along with the distance, are shown. The stations are between 2 and 62 km away from the closest storage facility, with only three facilities having stations closer than 6 km. Large distances between the UGS and ISD stations prevent us from using the ISD data for the plume dispersion model, because the ISD data may not be representative of the wind conditions at the storage facilities. To overcome this problem, we used model data at the facilities location. Nevertheless, the station data are used to verify the performances of the model at the ISD stations locations.

Table 1.B-4. ISD Stations considered in this study and the distance to the closest storage facility.

Storage Facility	Station Code	Station Latitude	Station Longitude	Distance (km)
Playa del Rey	KSMO	34.016	-118.451	5
Playa del Rey	KLAX	33.938	-118.388	6
Montebello	KFUL	33.872	-117.978	20
Montebello	KLGB	33.812	-118.146	24
Aliso Canyon	KVNY	34.21	-118.489	13
Aliso Canyon	KBUR	34.201	-118.357	22
Honor Rancho	KVNY	34.21	-118.489	29
Honor Rancho	KSDB	34.744	-118.724	34
La Goleta Gas	KSBA	34.426	-119.842	2
La Goleta Gas	KOXR	34.201	-119.206	62
Gill Ranch Gas	KMAE	36.988	-120.11	25
Gill Ranch Gas	KFAT	36.78	-119.719	47
McDonald Island Gas	KSCK	37.889	-121.225	25
McDonald Island Gas	KLVK	37.693	-121.814	45
Lodi Gas	KSCK	37.889	-121.225	35
Lodi Gas	KSAC	38.507	-121.495	42

Storage Facility	Station Code	Station Latitude	Station Longitude	Distance (km)
Los Medanos Gas	KCCR	37.992	-122.055	5
Los Medanos Gas	KSUU	38.267	-121.933	28
Wild Goose Gas	KOVE	39.49	-121.618	30
Wild Goose Gas	KMYV	39.102	-121.567	37
Princeton Gas	KOVE	39.49	-121.618	36
Princeton Gas	KMYV	39.102	-121.567	50
Kirby Hill Gas	KSUU	38.267	-121.933	11
Kirby Hill Gas	KCCR	37.992	-122.055	23
Pleasant Creek Gas	KVCB	38.378	-121.957	20
Pleasant Creek Gas	KSUU	38.267	-121.933	33

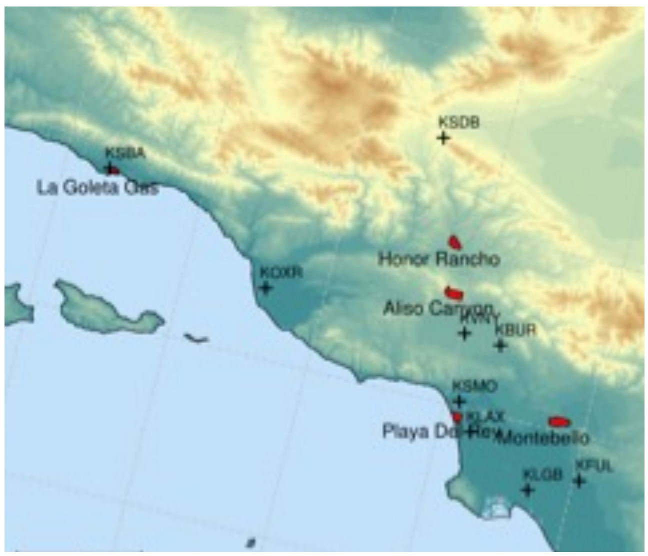


Figure 1.B-1. Location of Aliso Canyon, Honor Rancho, La Goleta Gas, Montebello and Playa del Rey as well as ISD meteorological stations close to the UGS facilities.

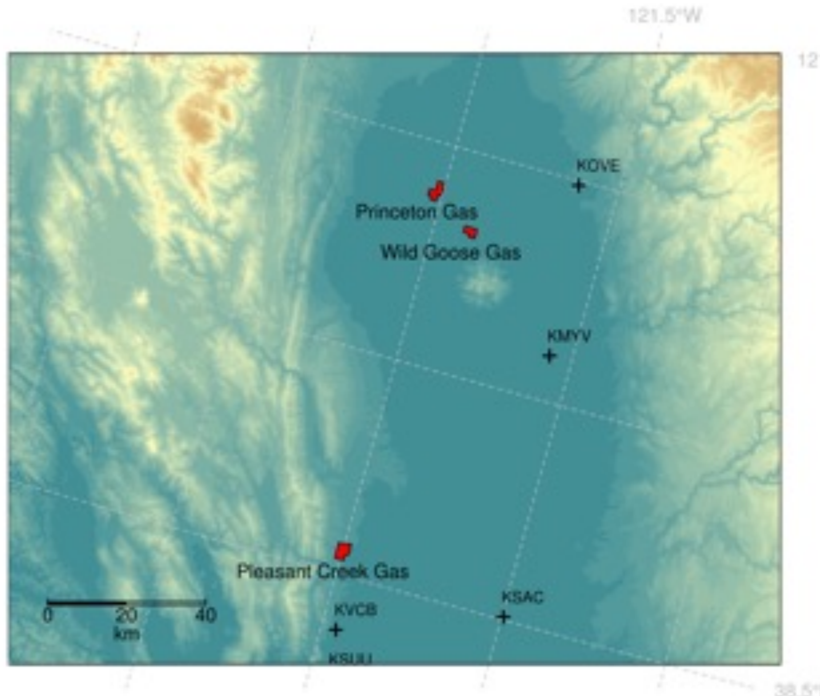


Figure 1.B-2. Location of Pleasant Creek Gas, Princeton Gas and Wild Goose Gas as well as ISD meteorological stations around the UGS facilities.

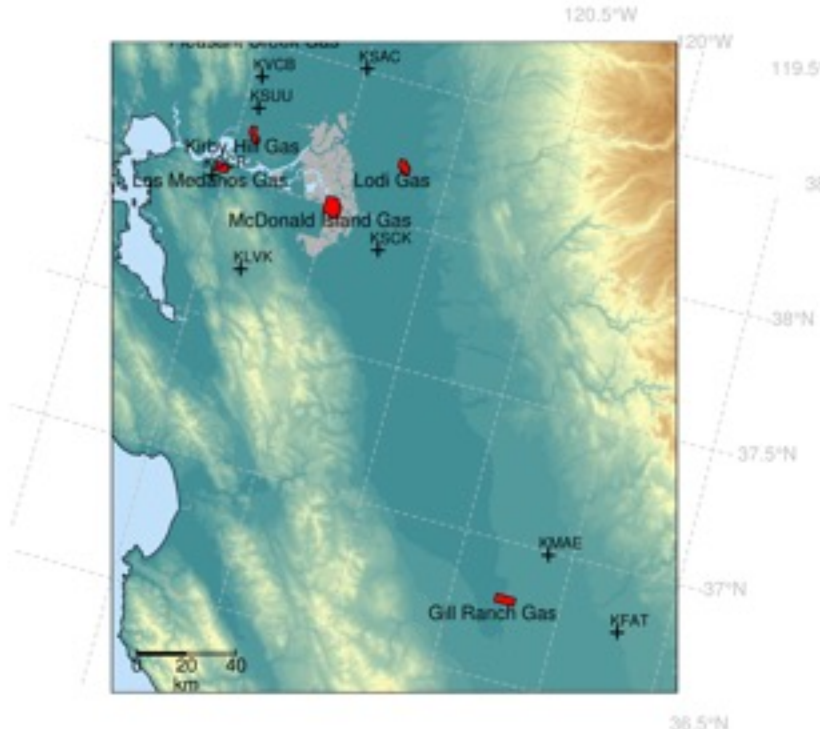


Figure 1.B-3. Location of Gill Ranch, Lodi Gas, Los Medanos Gas, Kirby Hill and McDonald Island Facilities as well as ISD meteorological stations in the vicinity of the UGS facilities.

The High-Resolution Rapid Refresh (HRRR) Model Data

The High-Resolution Rapid Refresh (HRRR) is a NOAA real-time 3 km resolution, hourly updated, cloud-resolving, convection-allowing atmospheric model initialized by 3 km grids with 3 km radar assimilation. Radar data are assimilated in the HRRR every 15 min over a 1 hr period adding further detail to that provided by the hourly data assimilation from the 13 km radar-enhanced Rapid Refresh.

It uses the community-based Advanced Research version of the Weather Research and Forecasting (WRF) Model (ARW) and Gridpoint Statistical Interpolation (GSI) analysis system. Modifications have been made to the community ARW model (especially in model physics) and GSI assimilation systems, some based on previous model and assimilation design innovations developed initially with the Rapid Update Cycle (RUC)

Model data for the period 08/15/2015 – 08/15/2016 were archived at National Institute of Standards and Technology (NIST) from the NCEP operational runs (http://nomads.ncep.noaa.gov/). Wind speed and direction at 10 m above ground along with the shortwave incoming radiation and cloud cover were extracted at the ISD locations and the storage facilities.

Meteorological datasets evaluation

Figure 1.B-4. shows the HRRR mean error (ME) and the mean absolute error (MAE) for wind speed and wind direction at the ISD locations for the period of interest. Due to the circular nature of wind direction, the differences were constrained to be between -180 and 180 degrees by measuring the angle of the differences larger than 180 (smaller than -180) in the opposite direction.

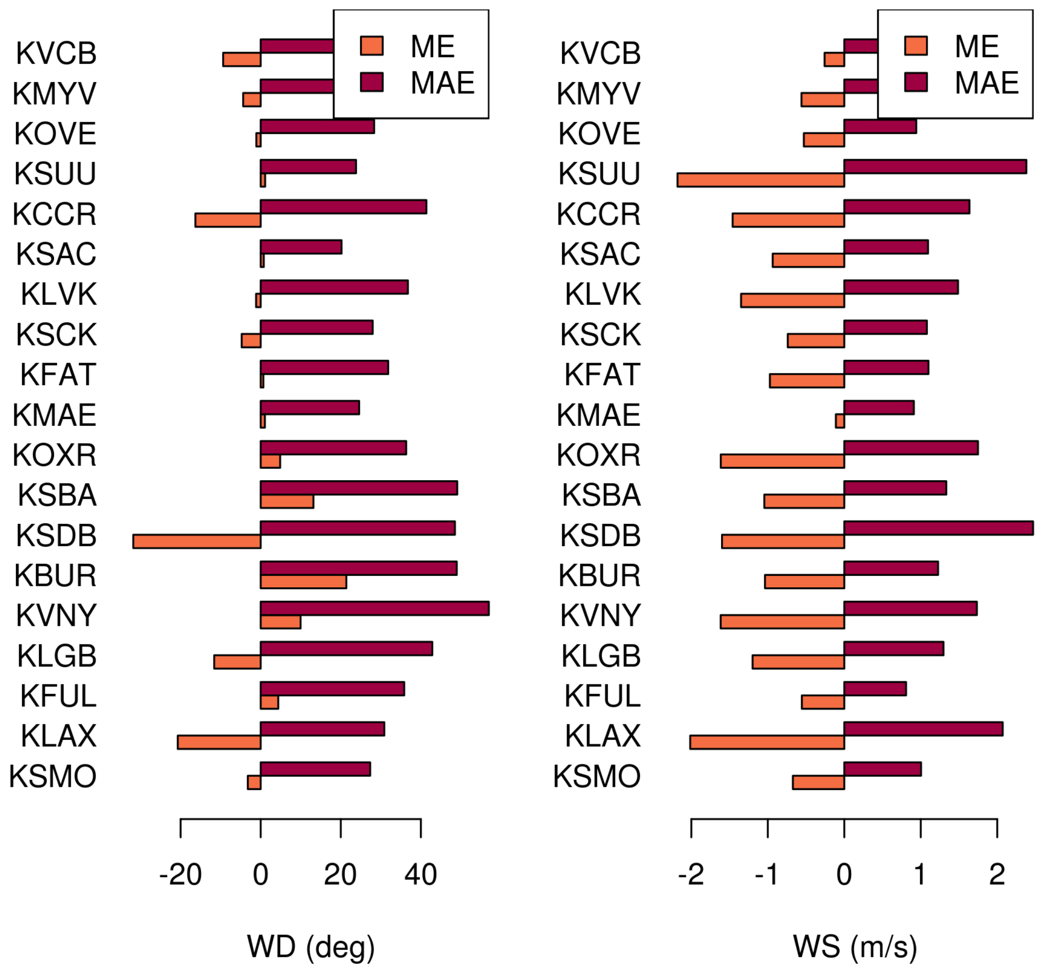


Figure 1.B-4. Mean Error (ME) and Mean Absolute Error (MAE) between HRRR model data and data collected at the ISD stations.

Overall, wind direction was well represented by the model, with ME below 10 degrees for most of the stations. Wind speed shows an overall underestimation of about 1 m/s. It is relevant to know that most of the ISD stations report wind speed 1 m/s bins and wind direction in 10 degree bins, which implies that the model ME is within the uncertainty limits of the stations. KSDB shows the worst performance for wind direction and speed. This is probably due to the very steep terrain around the station (Figure 1.B-4).

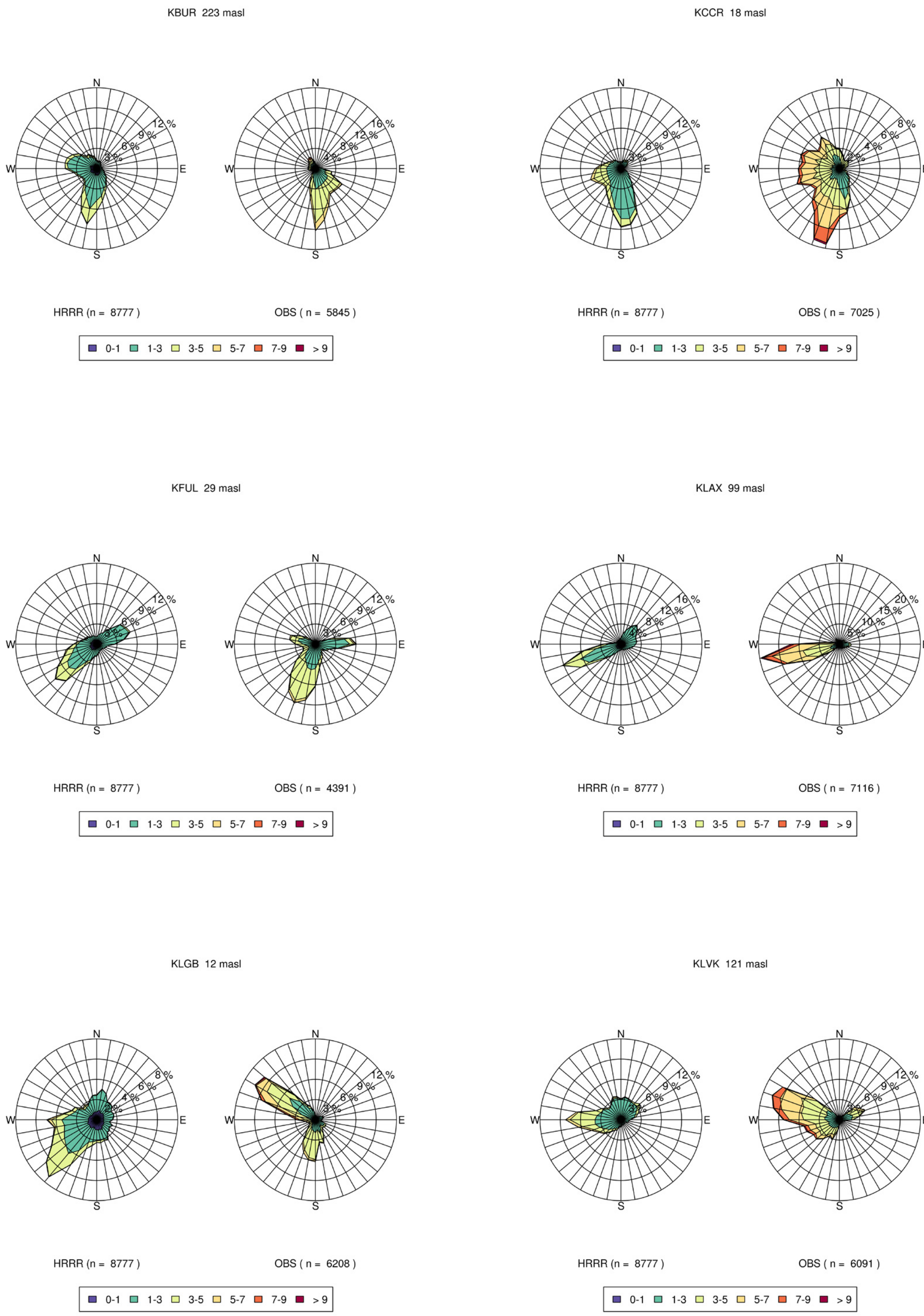


Figure 1.B-5. Comparison of annual wind rose data between HRRR with various weather stations.

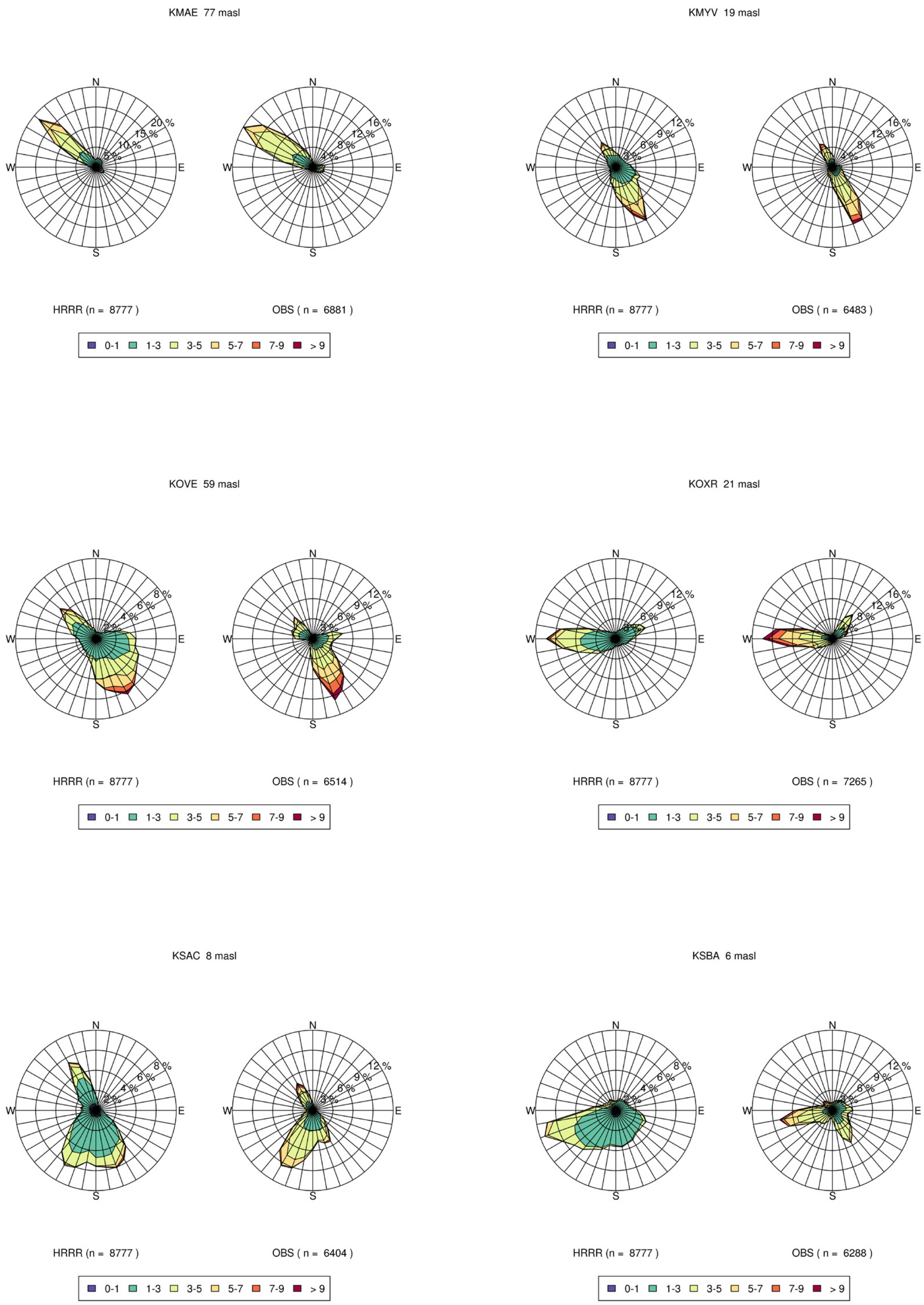


Figure 1.B-6. Comparison of annual wind rose data between HRRR with various weather stations.

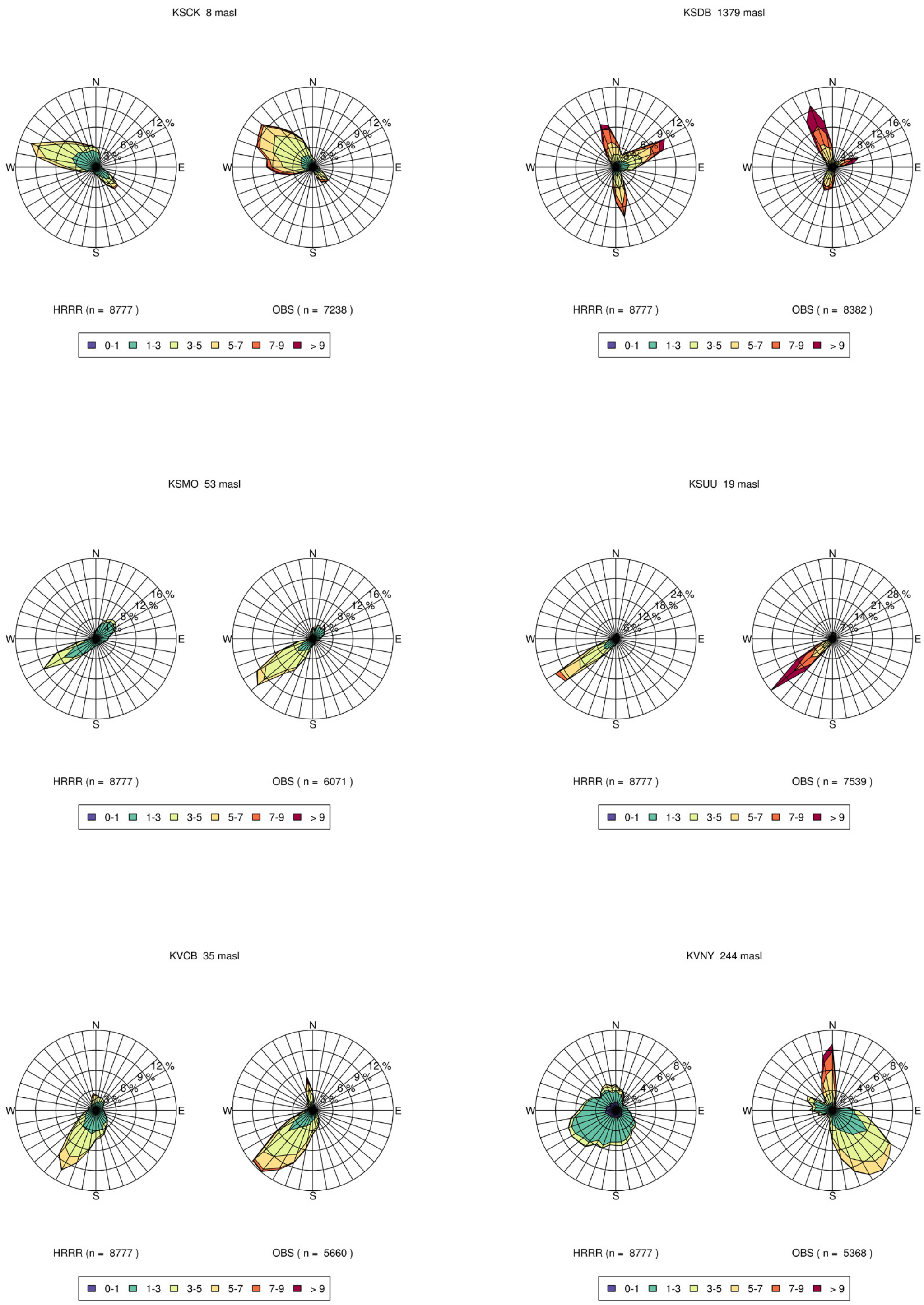


Figure 1.B-7. Comparison of annual wind rose data between HRRR with various weather stations.

1.B.1.1 HRRR Wind roses at the underground storage facilities

Figure 1.B-8 through Figure 1.B-19 show the annual wind roses for each storage facility obtained from the HRRR model data for the one-year period at four different times of the day; 00-06 (night), 06-12 (morning), 12-18 (afternoon), 18-00 (evening) PST to understand the dominant or primary wind directions (and speed).

For Aliso Canyon (Figure 1.B-8), main wind directions are N-NNE with high frequency of strong winds for most part of the day. However, during the afternoon, winds come from SSW with considerably lower wind speeds. Gill Ranch shows persistent winds from NW during the day with wind speeds in general between 1 and 5 m/s (2.2-11 mph). Stronger wind speeds, however, are present during the morning and afternoon. Honor Rancho shows high directionality during the afternoon and evening (SW), while the night and morning are much more variable, with directions from N-NW and SW-SE. Wind speeds are generally low during most of the day, with the exception of the afternoon when the winds are from 3 to 7 m/s and mornings where there are often strong winds from the NE. Kirby Hill Gas also shows high directionality with winds coming from SW during the entire day and stronger winds during the afternoon.

La Goleta presents winds from the W-SW during the afternoon and evening, being variable during nights and mornings SW-SE. Winds speeds are very low most of the day, with stronger values during the afternoon. Winds at Lodi Gas are from W-SW most of the day. However, during nights, winds are in almost the opposite direction, E-SE. Winds are generally very weak with the exception of afternoons and evenings, when the winds can be stronger. Wind patterns in Los Medanos Gas show interesting characteristics, with directions SW-S during nights and evenings and W-SW during mornings and afternoons. Wind speeds are generally between 1 and 7 m/s with higher frequency for speeds between 3 and 5 m/s. Again, wind speeds are stronger during the afternoon. McDonald Island Gas presents winds persistently from W-NW through the day, with some rare events from S-E mostly during nights and mornings. Winds are generally weak with the exception of the afternoons, when the winds tend to be stronger.

Montebello presents very weak winds during most of the day (1-3 m/s), with the exception of the afternoon, when the winds are slightly stronger, 3-5 m/s. SW directions are persistent through the day. However, opposite directions (NE) have some probability of occurrence, specifically during nights. Playa del Rey presents a wind pattern clearly affected by the sea breeze due to the proximity to the coast. During nights, winds are from inland (NE) while during afternoons, winds are from the ocean (SW). Mornings and evenings are transition times, and a combination of both direction can be seen. In general, wind speeds are weak (1-3 m/s) with stronger winds in the afternoons (3-5 m/s)

Pleasant Creek Gas shows variable wind patterns with directions NW in the night, N-NE in the morning, SW in the afternoon, and W-SW in the evening. Wind speeds are stronger in the mornings, but with some probability of strong winds during other periods of the day.

Winds at Princeton Gas are mostly from SE, with equal probability of being NW during nights and mornings. Stronger winds occur during mornings and evenings, but with some probability of occurrence during evenings and nights as well. Well-defined direction can be found at Wild Goose Gas during mornings and evenings, being NNW for the former and SSE for the latter. During nights, winds are from W, SE, and NW, while during the evenings, winds are quite variable, with directions ranging from SSW–SE. Wind speeds are generally low, with larger values during mornings and afternoons.

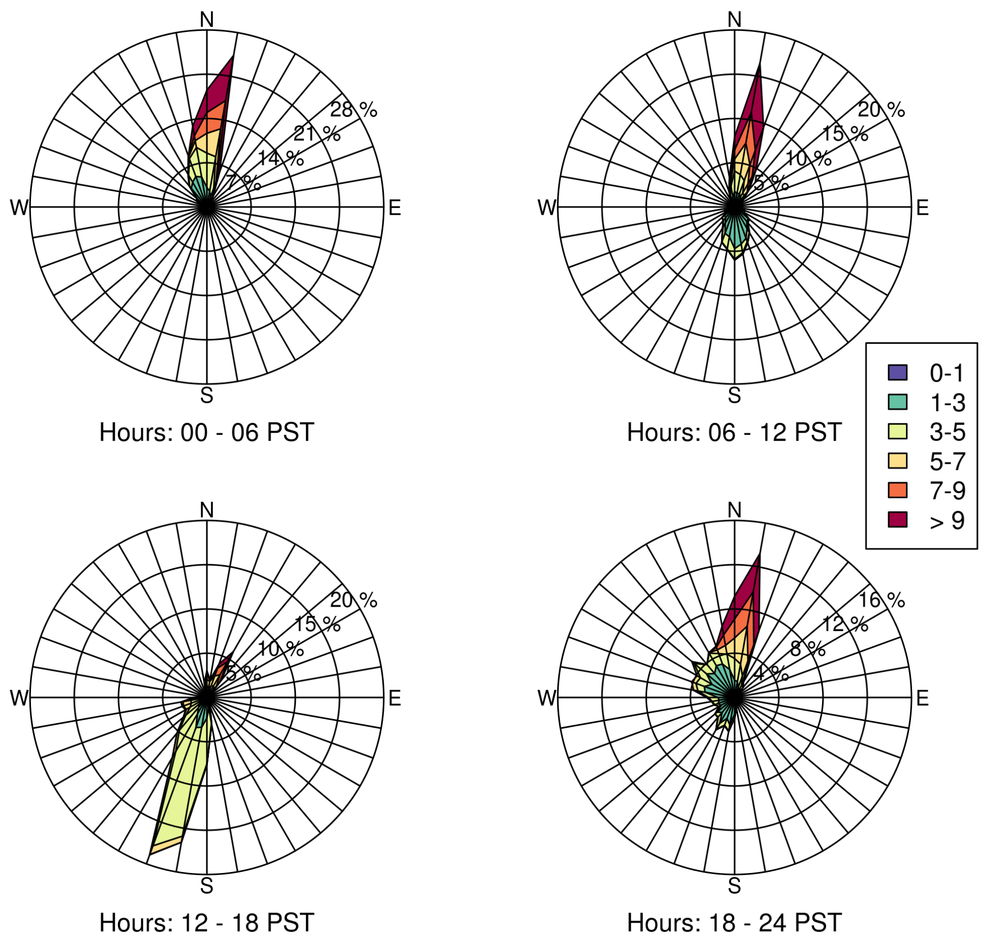


Figure 1.B-8. Wind roses at the Aliso Canyon UGS facility obtained from HRRR data.

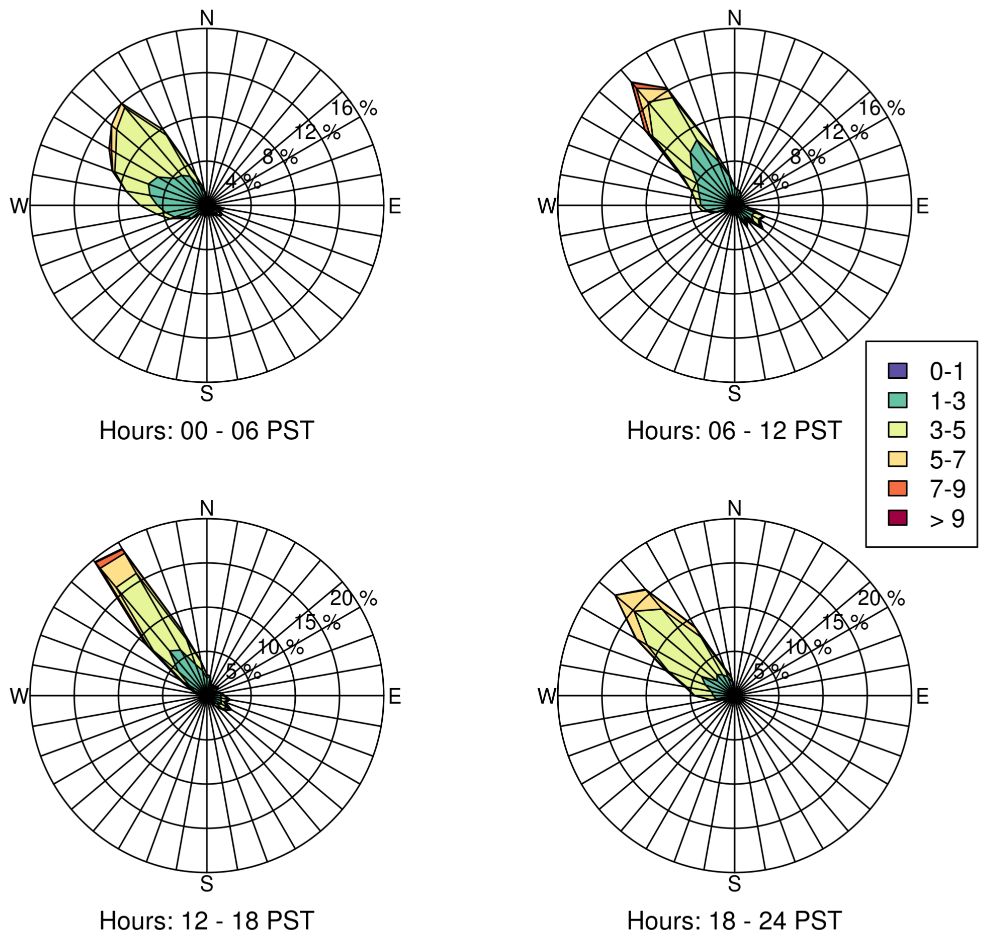


Figure 1.B-9. Wind roses at the Gill Ranch UGS facility obtained from HRRR data.

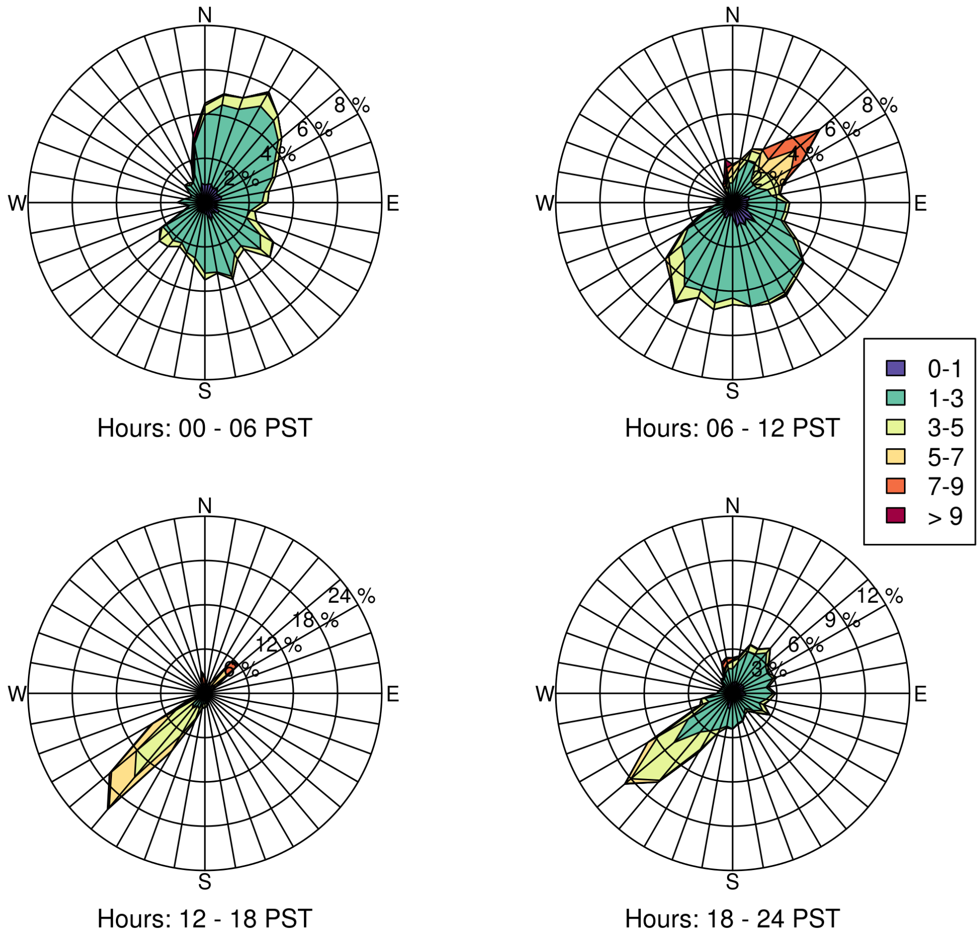


Figure 1.B-10. Wind roses at the Honor Rancho facility obtained from HRRR data.

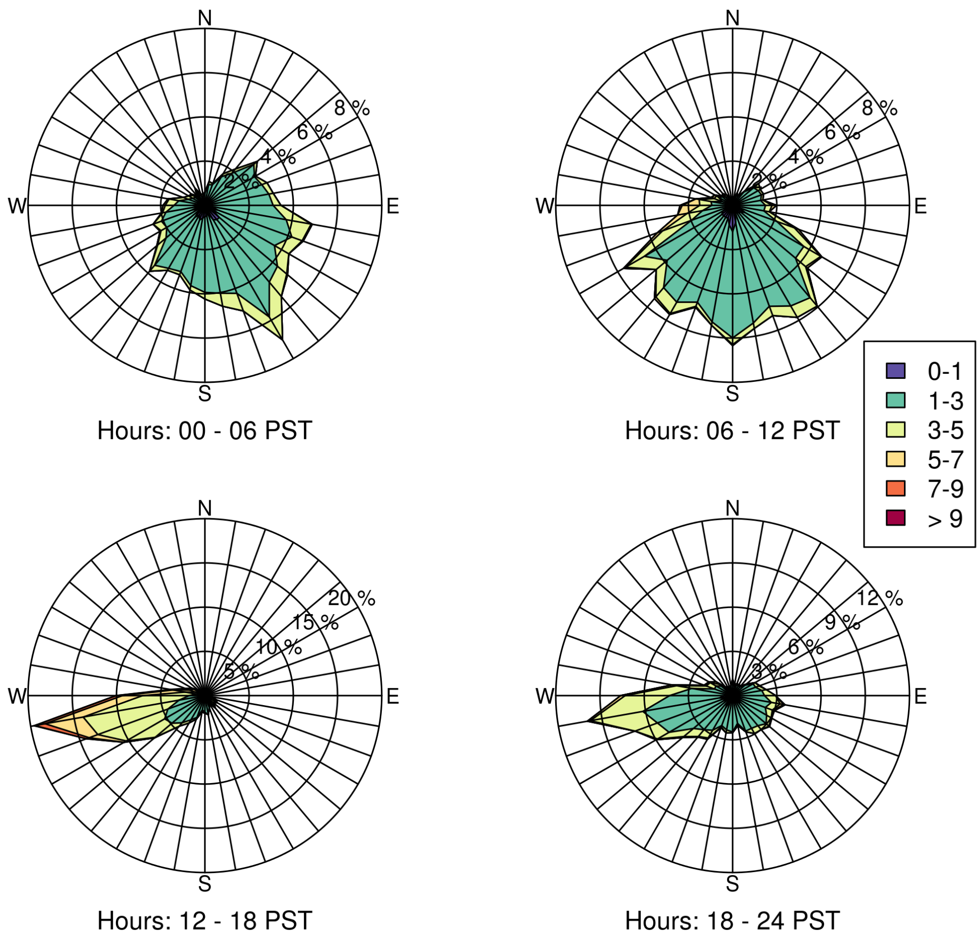


Figure 1.B-11. Wind roses at the La Goleta Gas facility obtained from HRRR data.

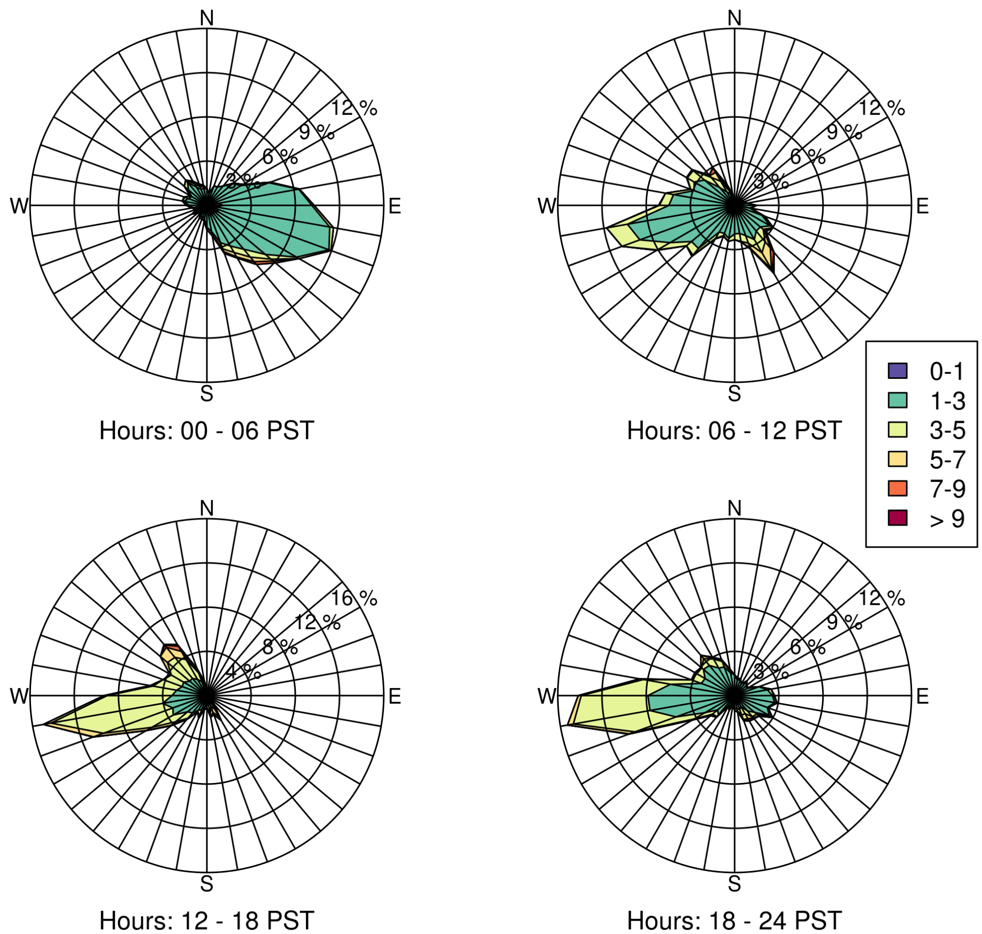


Figure 1.B-12. Wind roses at the Lodi Gas facility obtained from HRRR data.

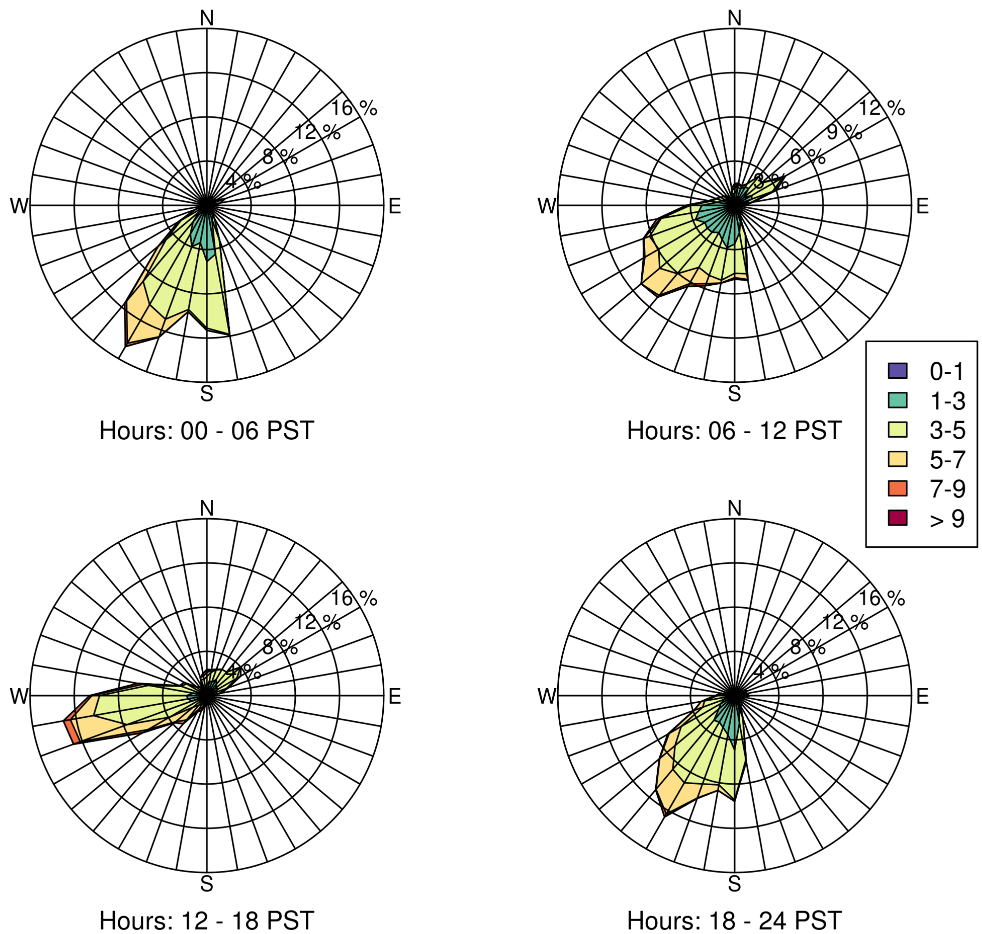


Figure 1.B-13. Wind roses at the Los Medanos UGS facility obtained from HRRR data.

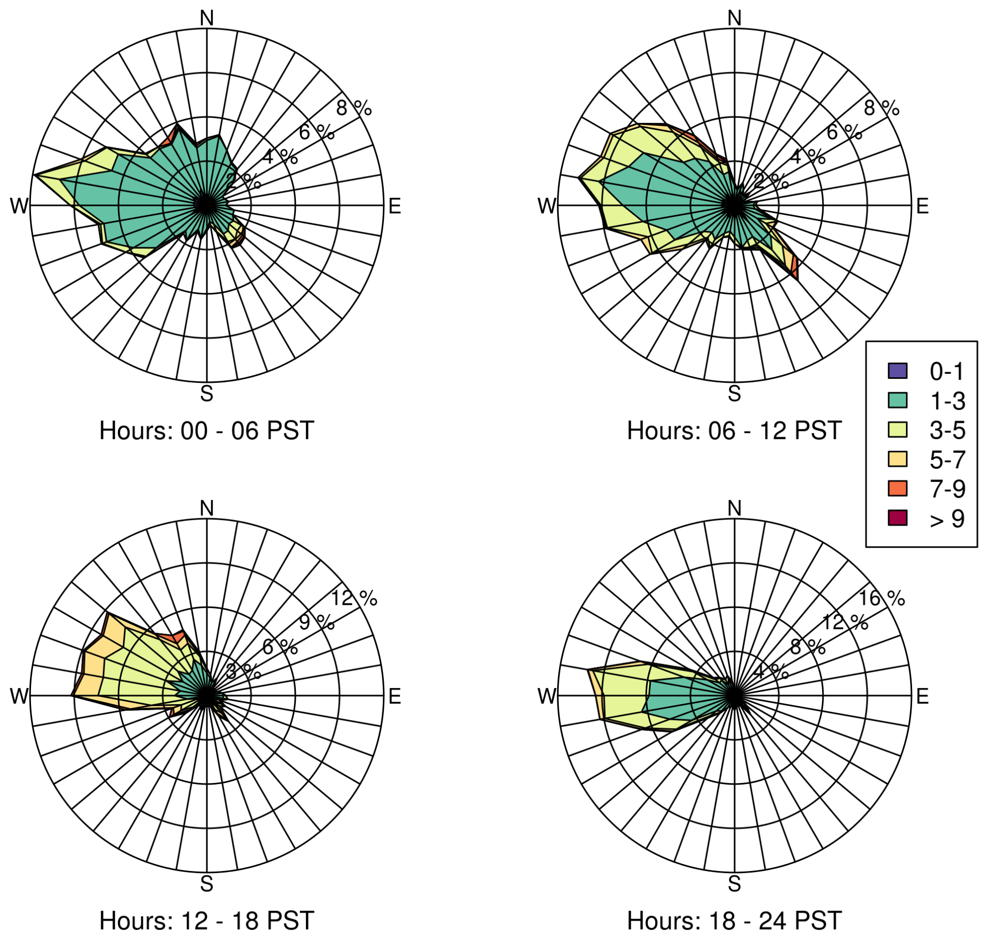


Figure 1.B-14. Wind roses at the McDonald Islafacility obtained from HRRR data.

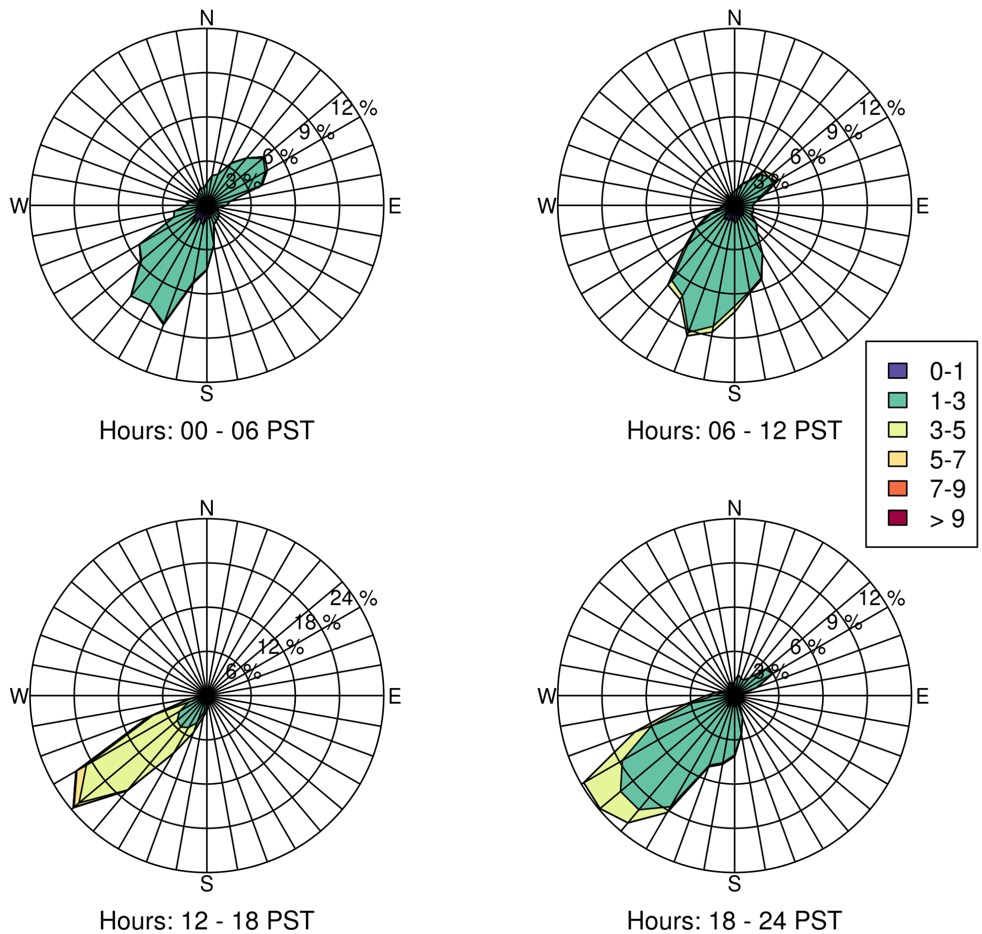


Figure 1.B-15. Wind roses at the Montebello UGS facility obtained from HRRR data.

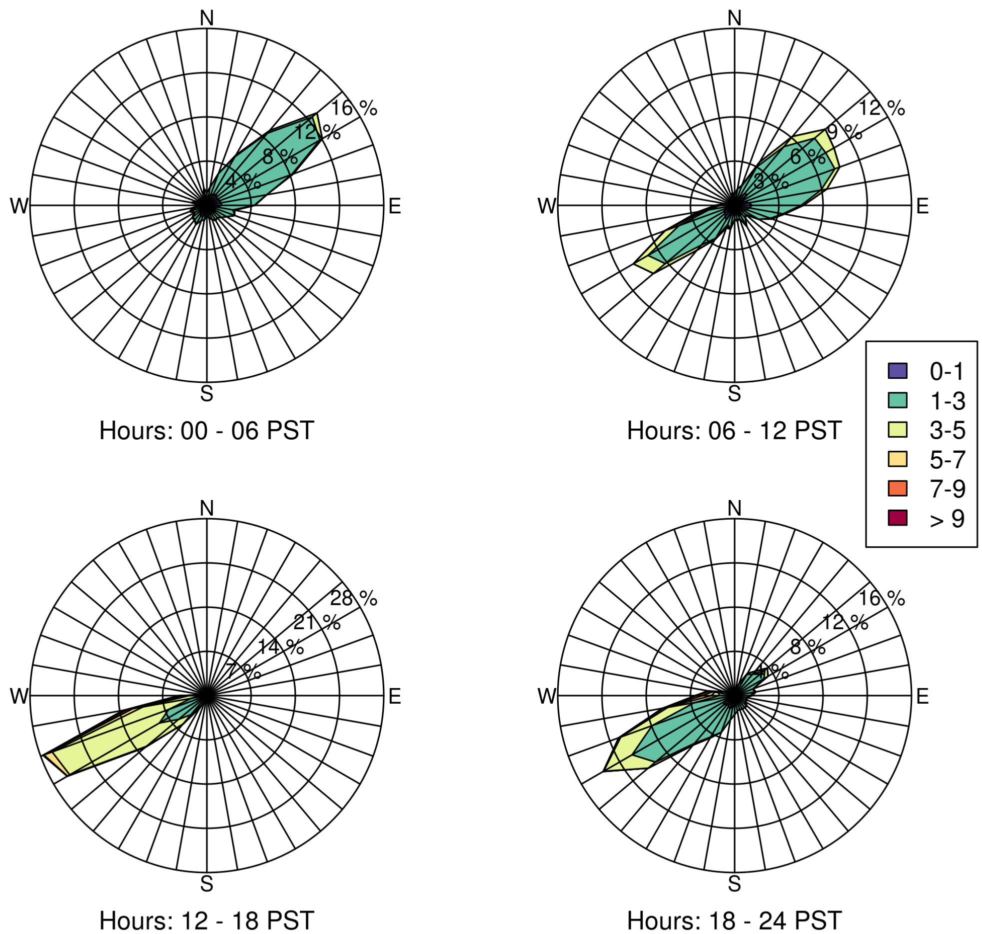


Figure 1.B-16. Wind roses at the Playa del Rey UGS facility obtained from HRRR data.

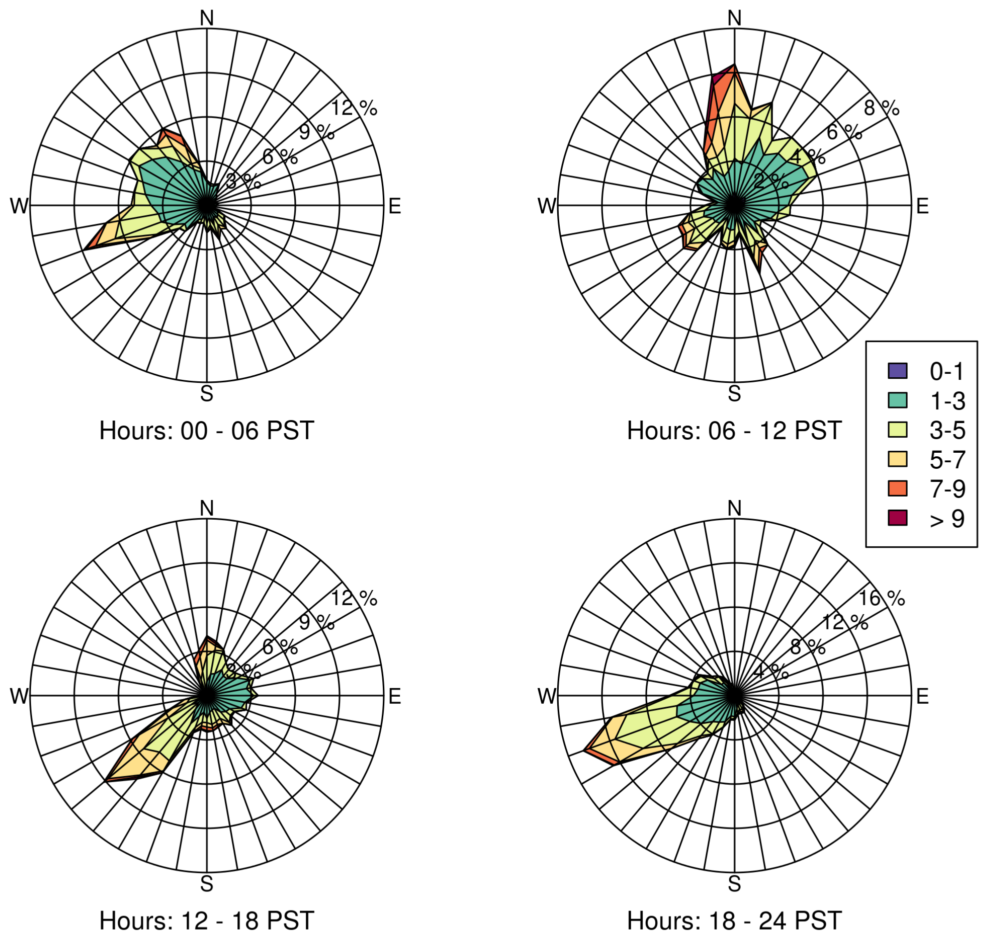


Figure 1.B-17. Wind roses at the Pleasant Creek UGS facility obtained from HRRR data.

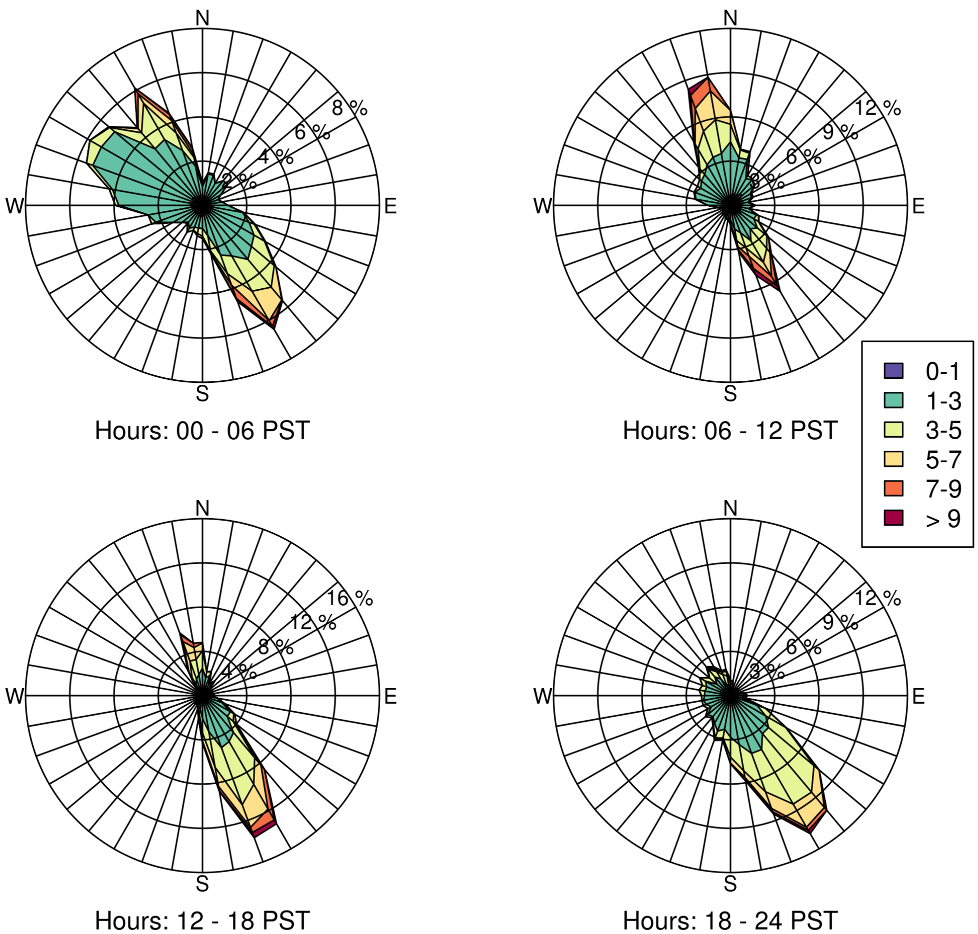


Figure 1.B-18. Wind roses at the Princeton UGS facility obtained from HRRR data.

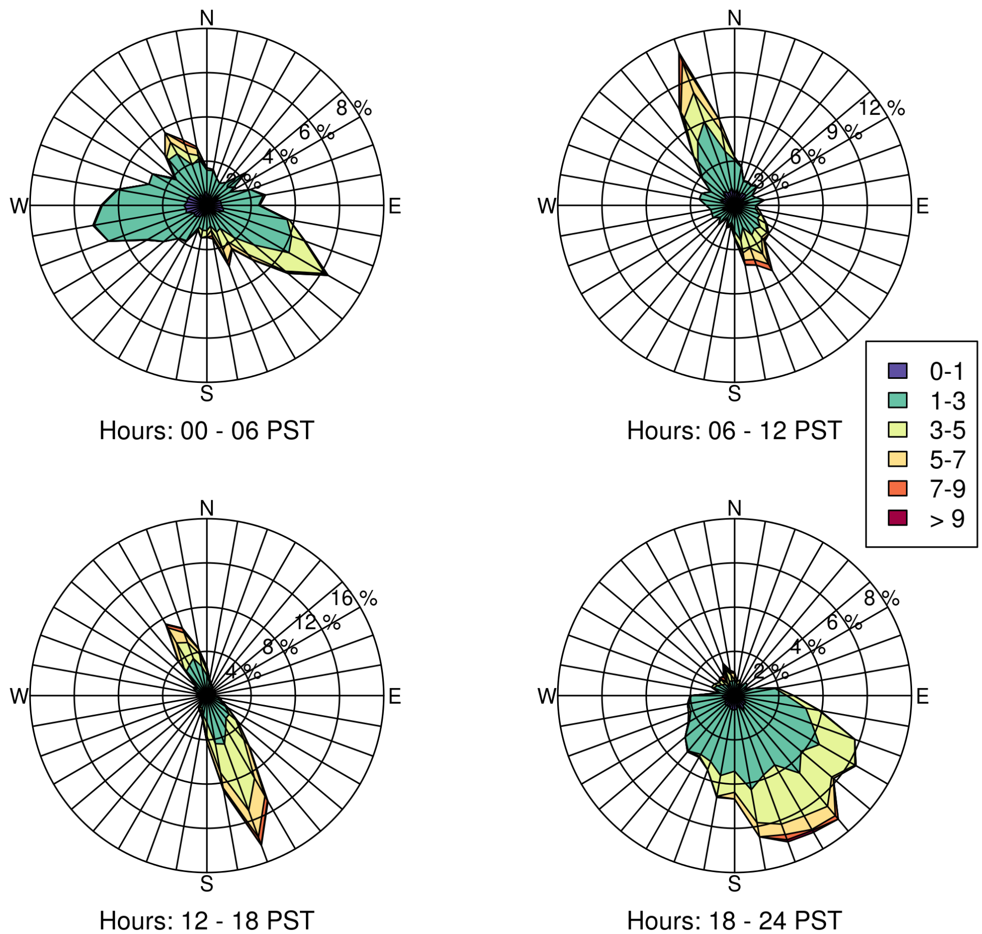


Figure 1.B-19. Wind roses at the Wild Goose UGS facility obtained from HRRR data.

Pasquill Stability Type

Identified Pasquill stability classes for each storage facility are shown in Table 1.B-5. Overall, classes F and B are the most frequent categories. Aliso Canyon is an exception, as it shows the highest frequency for Category D, which is almost that of other facilities. Category A is most frequent at Playa del Rey, Montebello, Wild Goose Gas, and Princeton Gas facilities, which also show a high frequency of Category B events.

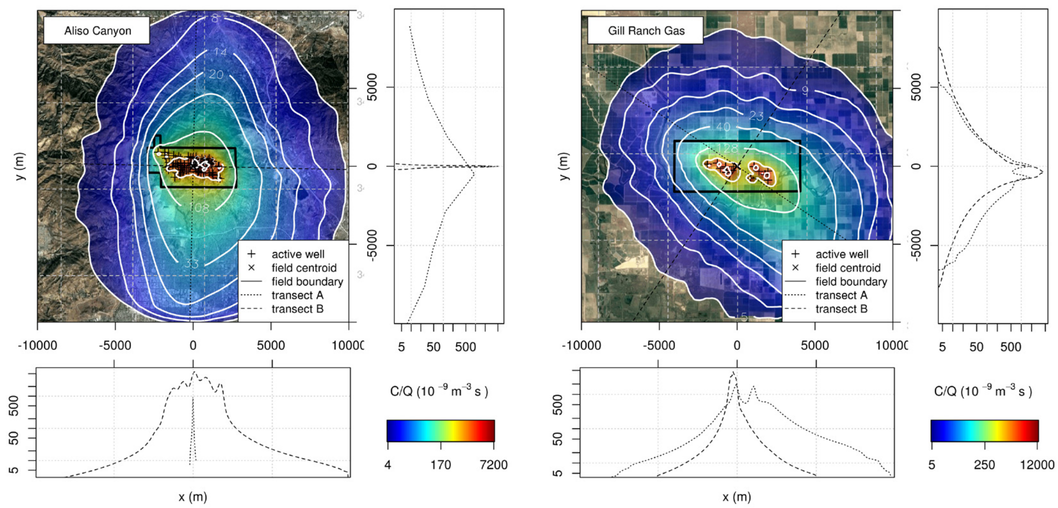
Table 1.B-5. Frequency of Pasquill Stability Type (%).

	A	B	C	D	E	F
Playa del Rey	10.1	26.4	12.5	3.4	14.7	33
Montebello	11.3	27	11.2	1.4	11.7	37.5
Aliso Canyon	6.7	20.2	15.5	22.8	13.5	21.3
Honor Rancho	9.4	21	13.2	9.7	10.3	36.4
La Goleta Gas	8.8	25.8	12.4	5.7	16.1	31.2
Gill Ranch Gas	9.4	24.5	13.2	8.1	23.3	21.5
McDonald Island Gas	8.4	24.8	12.4	8.8	14.2	31.4
Lodi Gas	8	26.6	12.5	7.1	12.4	33.5
Los Medanos Gas	3.1	22.1	18.8	15.1	25.2	15.6
Wild Goose Gas	12.4	23.5	10.5	8.9	14.3	30.5
Princeton Gas	10.6	22.2	11.8	13.1	16.3	26
Kirby Hill Gas	5.9	22.1	15.3	14.7	19.7	22.3
Pleasant Creek Gas	6.6	24.3	13.8	13.1	16.9	25.3

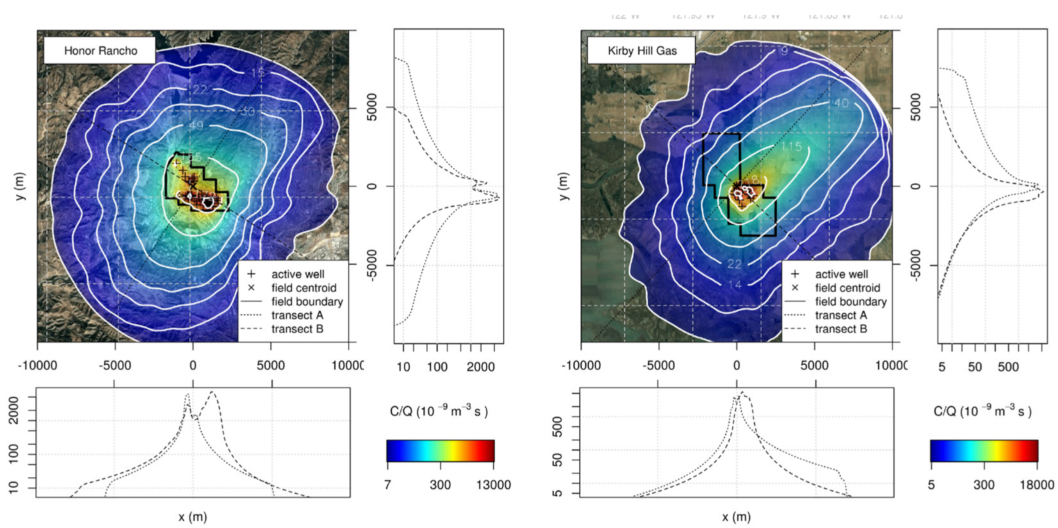
1.B.1.2 Exposure climatology mapping

In order to analyze the concentration over flux ratio (C/Q) values, six contour levels were selected. The contour levels were selected as 65, 75, 85, 95, 99, 99.9 percentiles of the cumulative distribution. Considering the total area of the grid, those percentile levels can be interpreted as the area under the contour value, being approximately 175, 125, 75, 25, 5, 0.5 km^2.

Larger concentrations are always found during nights and evenings, as expected. This is due to the increased atmospheric stability and generally calmer winds during nights. Overall, night–afternoon differences are approximately 2–12 times, depending on the contour level and facility, with a mean of 3.7 times. Playa del Rey exhibits the largest differences, while Los Medanos exhibits the smallest difference between night-afternoon hours.

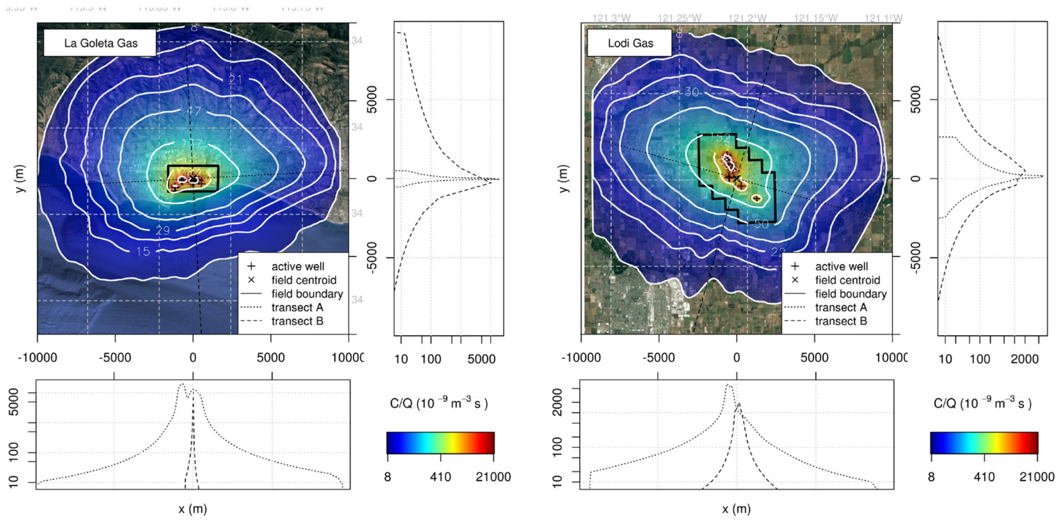


(a) (b)

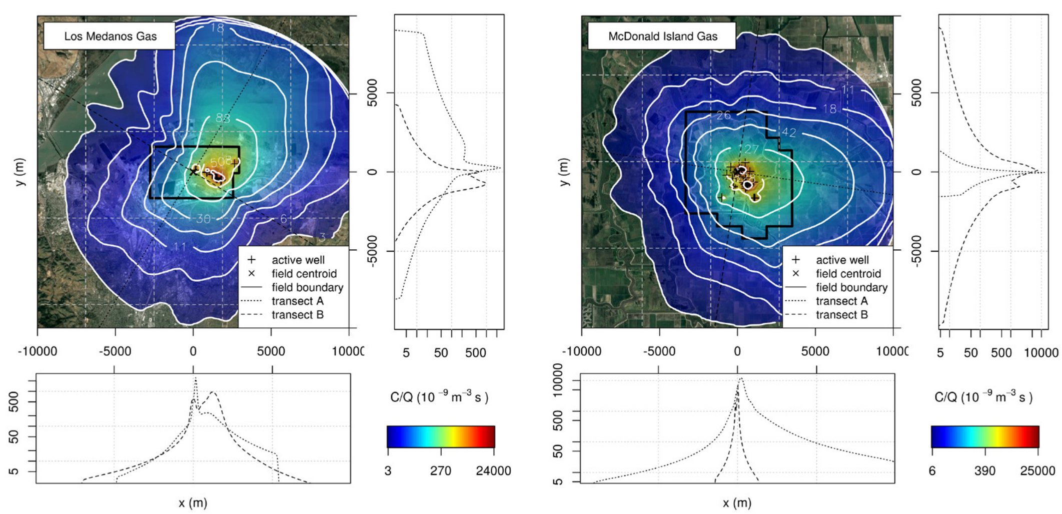


(c) (d)

Figure 1.B-20. Annual mean tracer concentration over flux ratio for Aliso Canyon (a) and Gill Ranch (b), Honor Rancho (c) and Kirby Hill (d) UGS facilities. Side panels are the concentration profiles along the transects marked on the map.



(a) (b)



(c) (d)

Figure 1.B-21. Annual mean tracer concentration over flux ratio for La Goleta (a), Lodi Gas (b), Los Medanos Gas (c) and McDonald Island (d) UGS facilities. Side panels are the concentration profiles along the transects marked on the map.

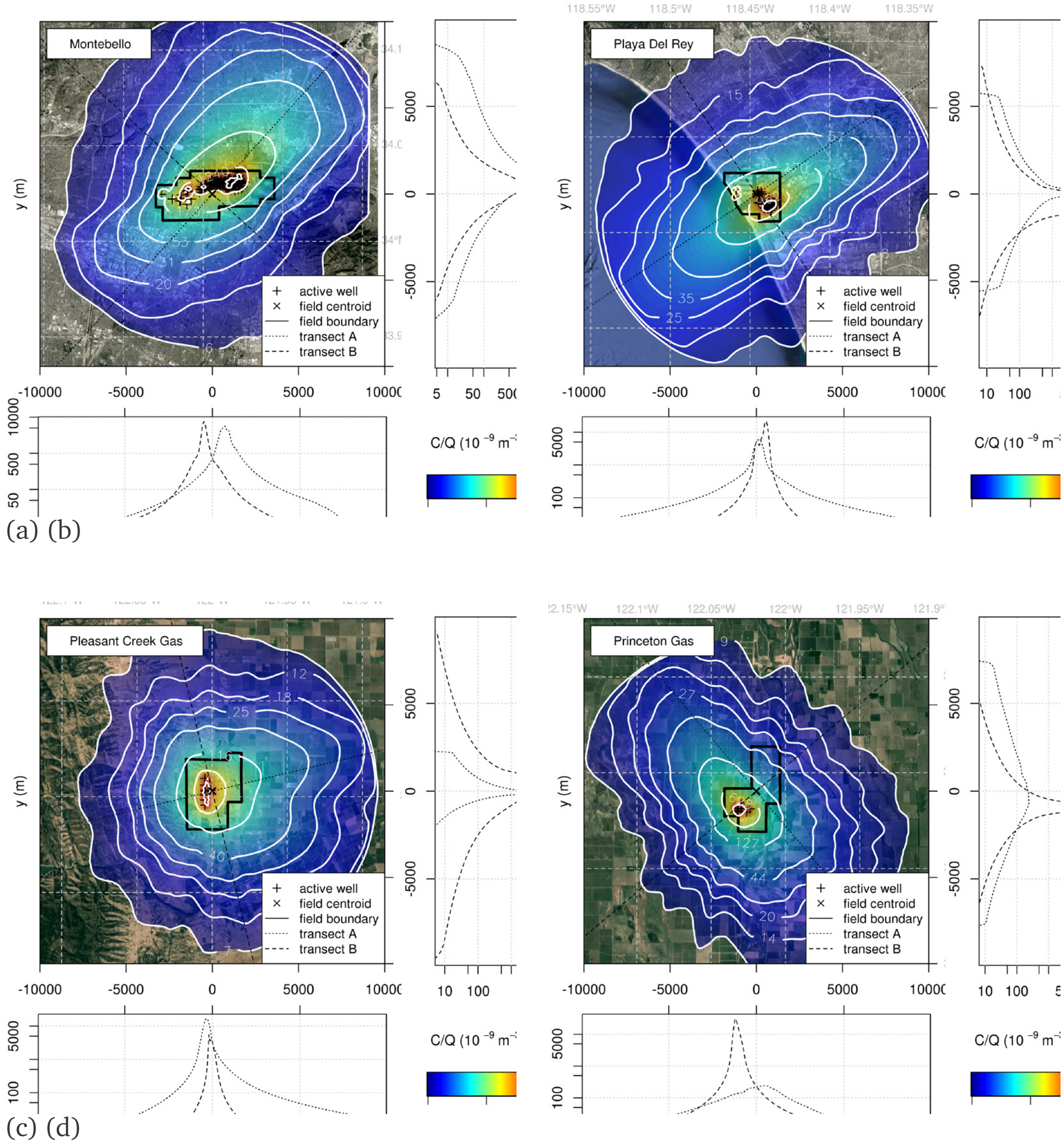


Figure 1.B-22. Annual mean tracer concentration over flux ratio for Montebello (a), Playa del Rey (b), Pleasant Creek Gas (c) and Princeton Gas (d) UGS facilities. Side panels are the concentration profiles along the transects marked on the map.

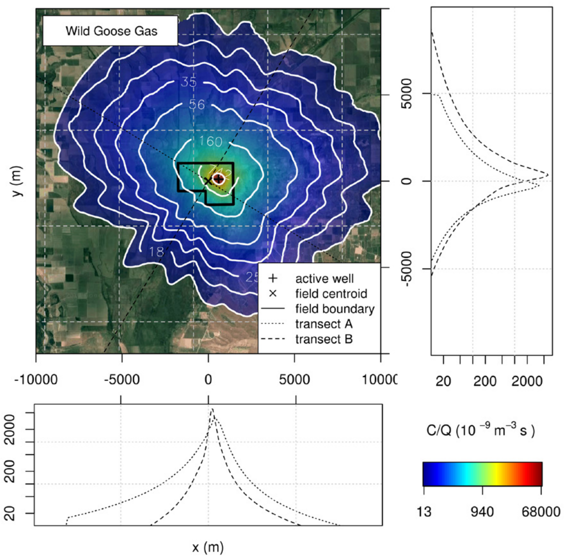
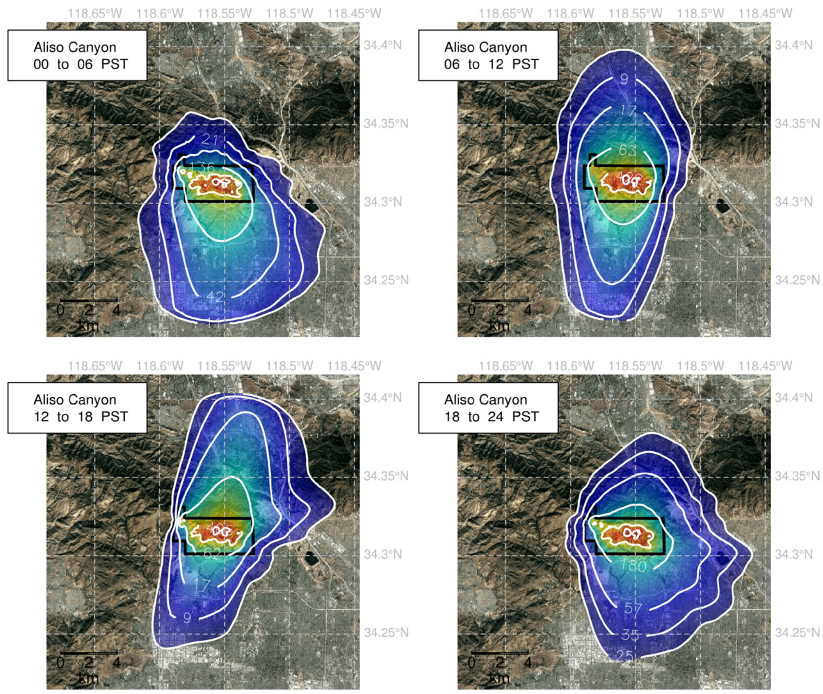
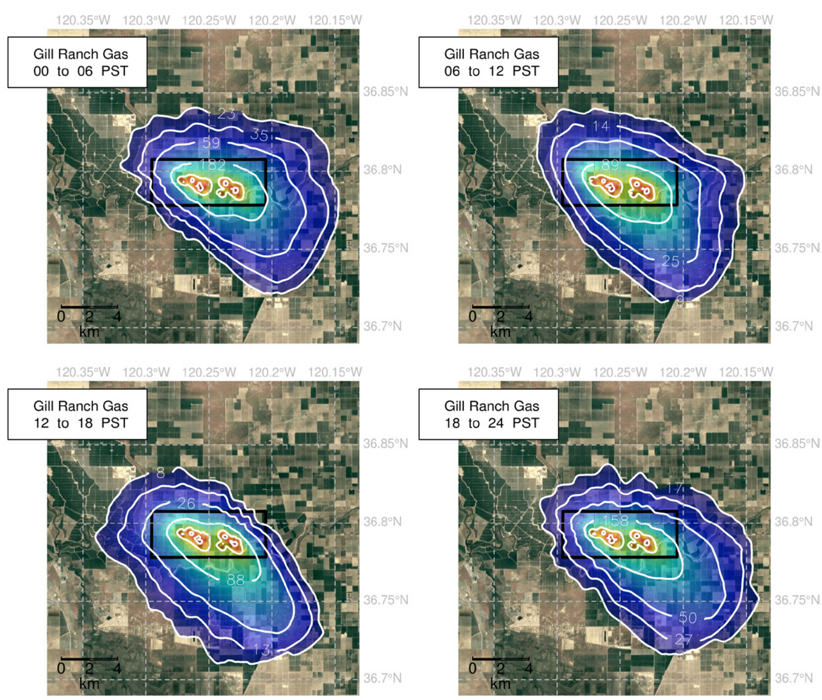
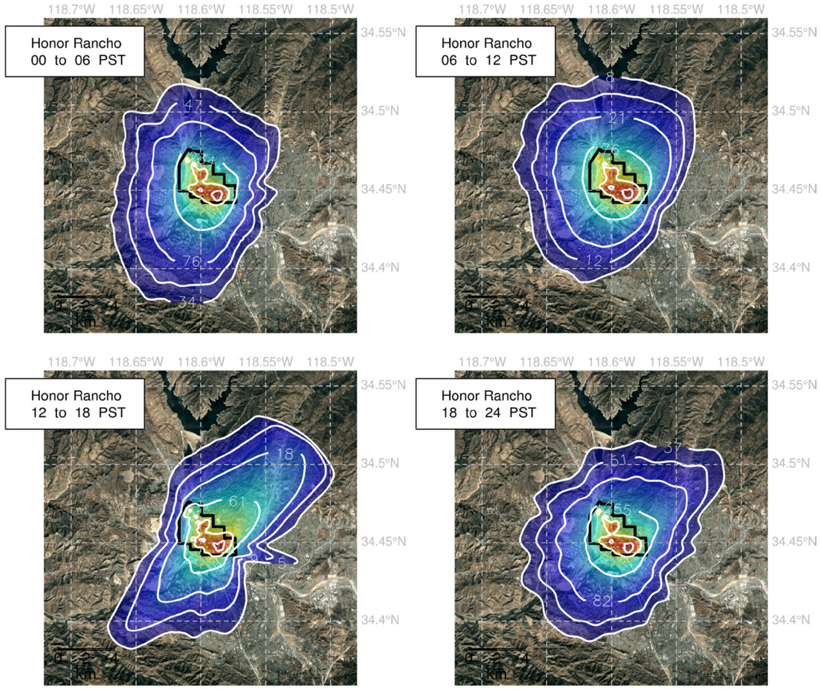


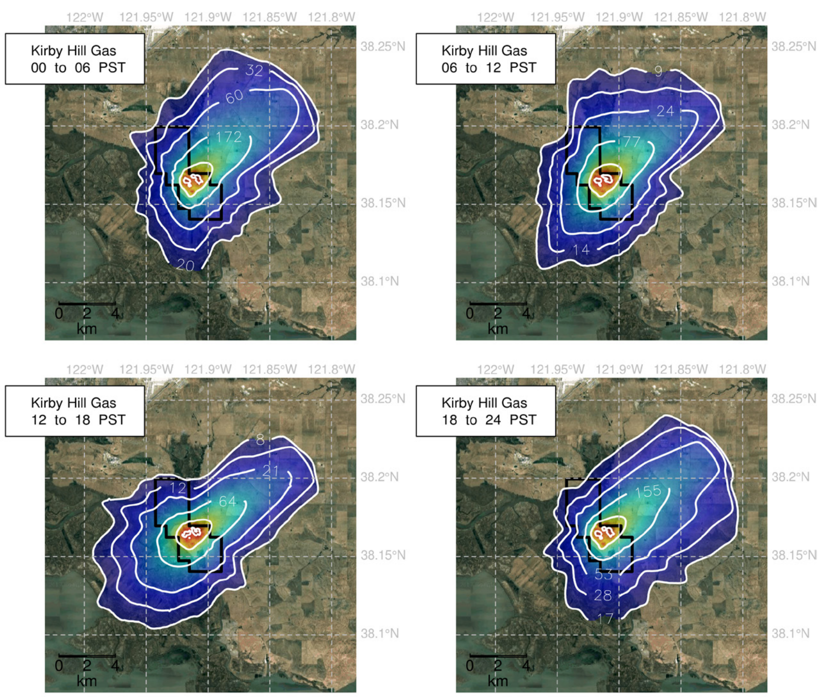
Figure 1.B-23. Annual mean tracer concentration over flux ratio for Wild Goose UGS facility. Side panels are the concentration profiles along the transects marked on the map.

1.B.2 Dispersion Modeling Contours for Flammability Assessment






Honor Rancho
00 to 06 PST
Honor Rancho
06 to 12 PST
Honor Rancho
12 to 18 PST
Honor Rancho
18 to 24 PST
118.7°W 118.65°W 118.6°W 118.55°W 118.5°W
34.55°N
34.5°N
34.45°N
34.4°N
0 2 4
km


Kirby Hill Gas
00 to 06 PST
Kirby Hill Gas
06 to 12 PST
Kirby Hill Gas
12 to 18 PST
Kirby Hill Gas
18 to 24 PST
122°W 121.95°W 121.9°W 121.85°W 121.8°W
38.25°N
38.2°N
38.15°N
38.1°N
0 2 4
km

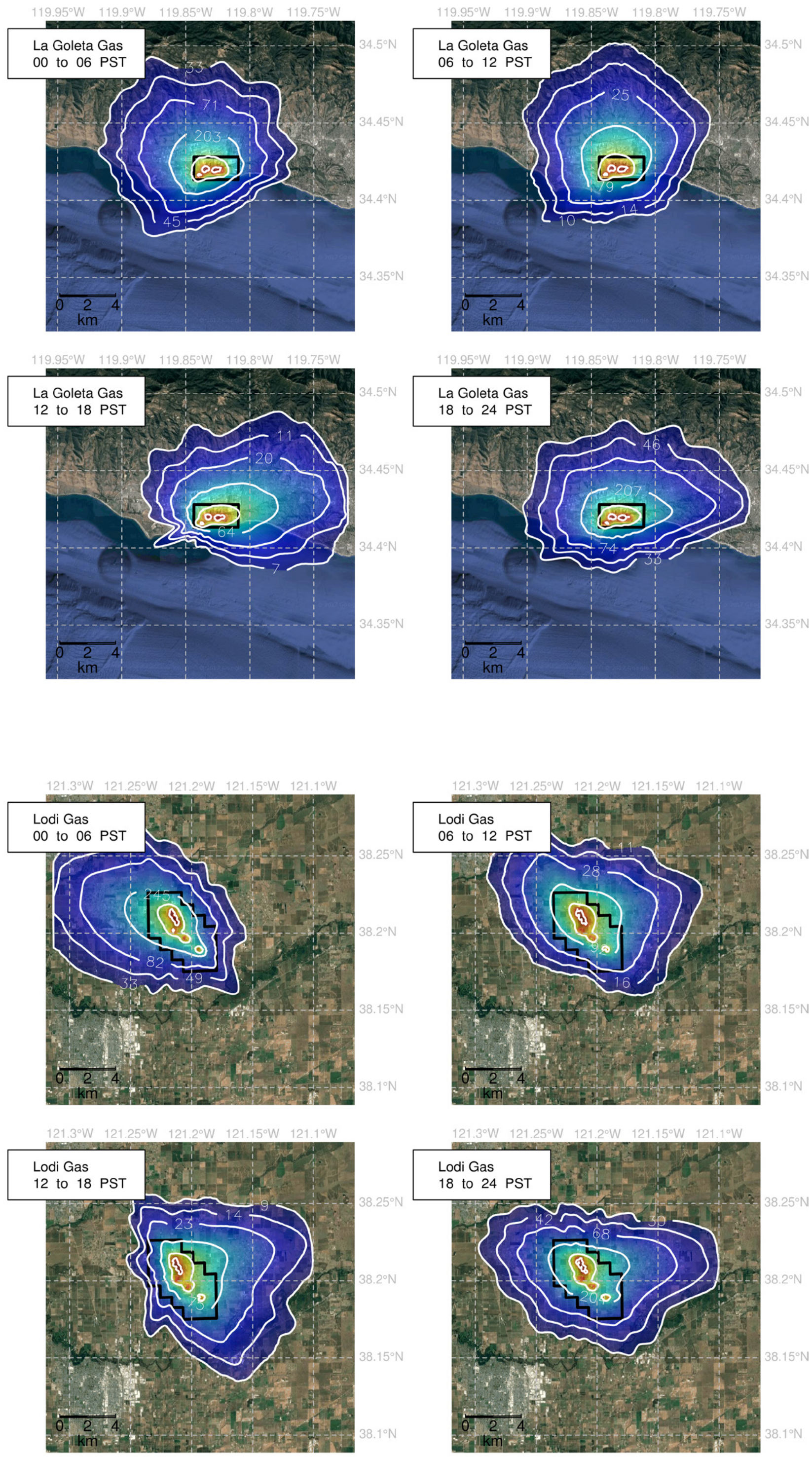
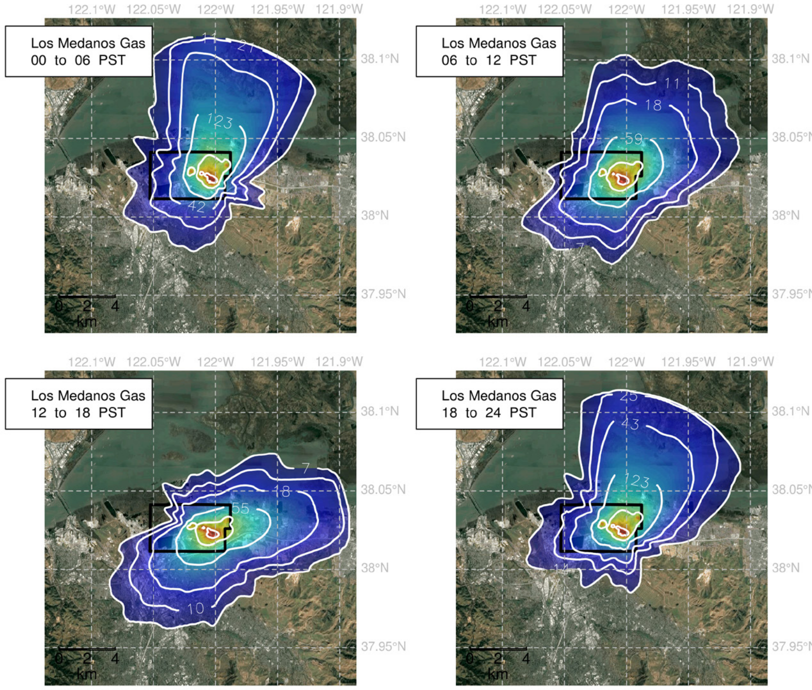
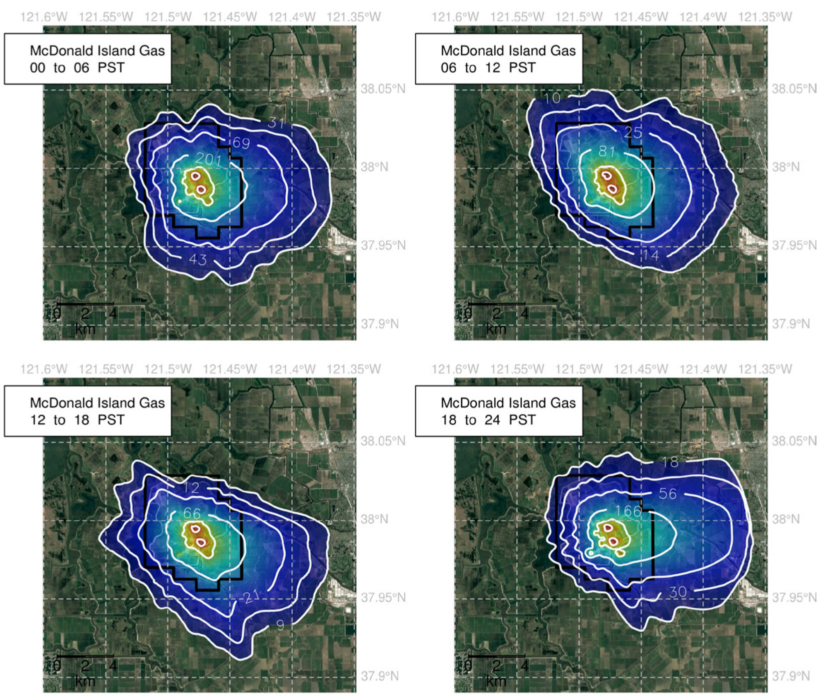
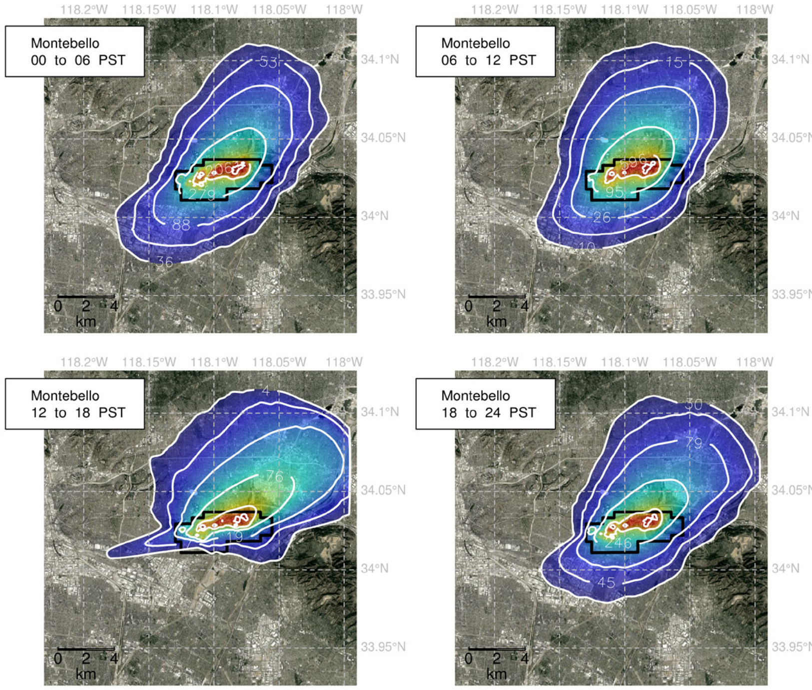
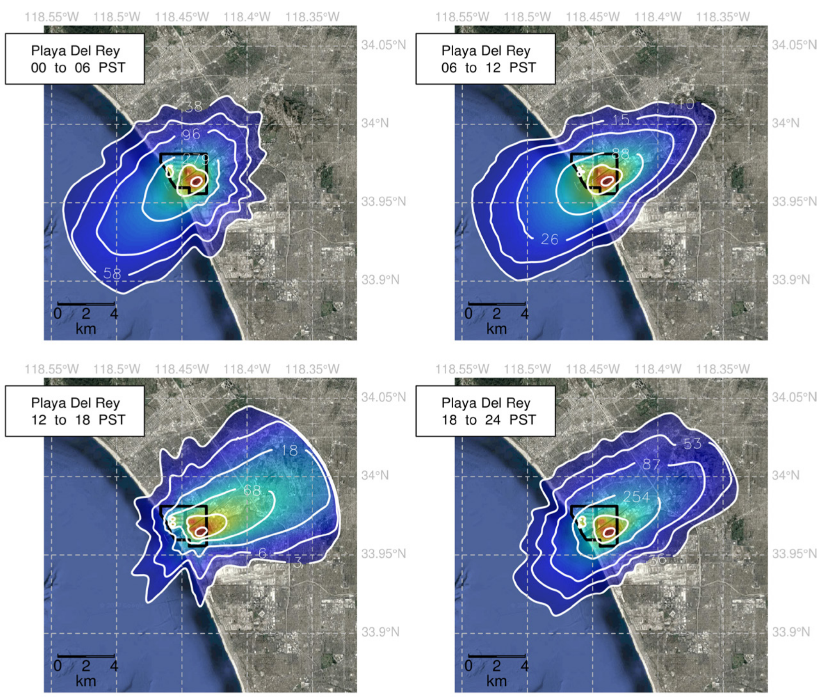


Figure 1.B-24. Mean tracer concentration over flux ratio (ug m^{-3} / ug s^{-1}) scaled by 10^9 at various underground storage facility for the four time bins (00-06 PST, 06-12 PST, 12-18 PST and 18-24 PST). The black contour shows the extent of the storage facility.


Los Medanos Gas
00 to 06 PST
Los Medanos Gas
06 to 12 PST
Los Medanos Gas
12 to 18 PST
Los Medanos Gas
18 to 24 PST
122.1°W 122.05°W 122°W 121.95°W 121.9°W
38.1°N
38.05°N
38°N
37.95°N
0 2 4
km


McDonald Island Gas
00 to 06 PST
McDonald Island Gas
06 to 12 PST
McDonald Island Gas
12 to 18 PST
McDonald Island Gas
18 to 24 PST
121.6°W 121.55°W 121.5°W 121.45°W 121.4°W 121.35°W
38.05°N
38°N
37.95°N
37.9°N
0 2 4
km


Montebello
00 to 06 PST
Montebello
06 to 12 PST
Montebello
12 to 18 PST
Montebello
18 to 24 PST
118.2°W
118.15°W
118.1°W
118.05°W
118°W
34.1°N
34.05°N
34°N
33.95°N
0 2 4
km


Playa Del Rey
00 to 06 PST
Playa Del Rey
06 to 12 PST
Playa Del Rey
12 to 18 PST
Playa Del Rey
18 to 24 PST
118.55°W
118.5°W
118.45°W
118.4°W
118.35°W
34.05°N
34°N
33.95°N
33.9°N
0 2 4
km

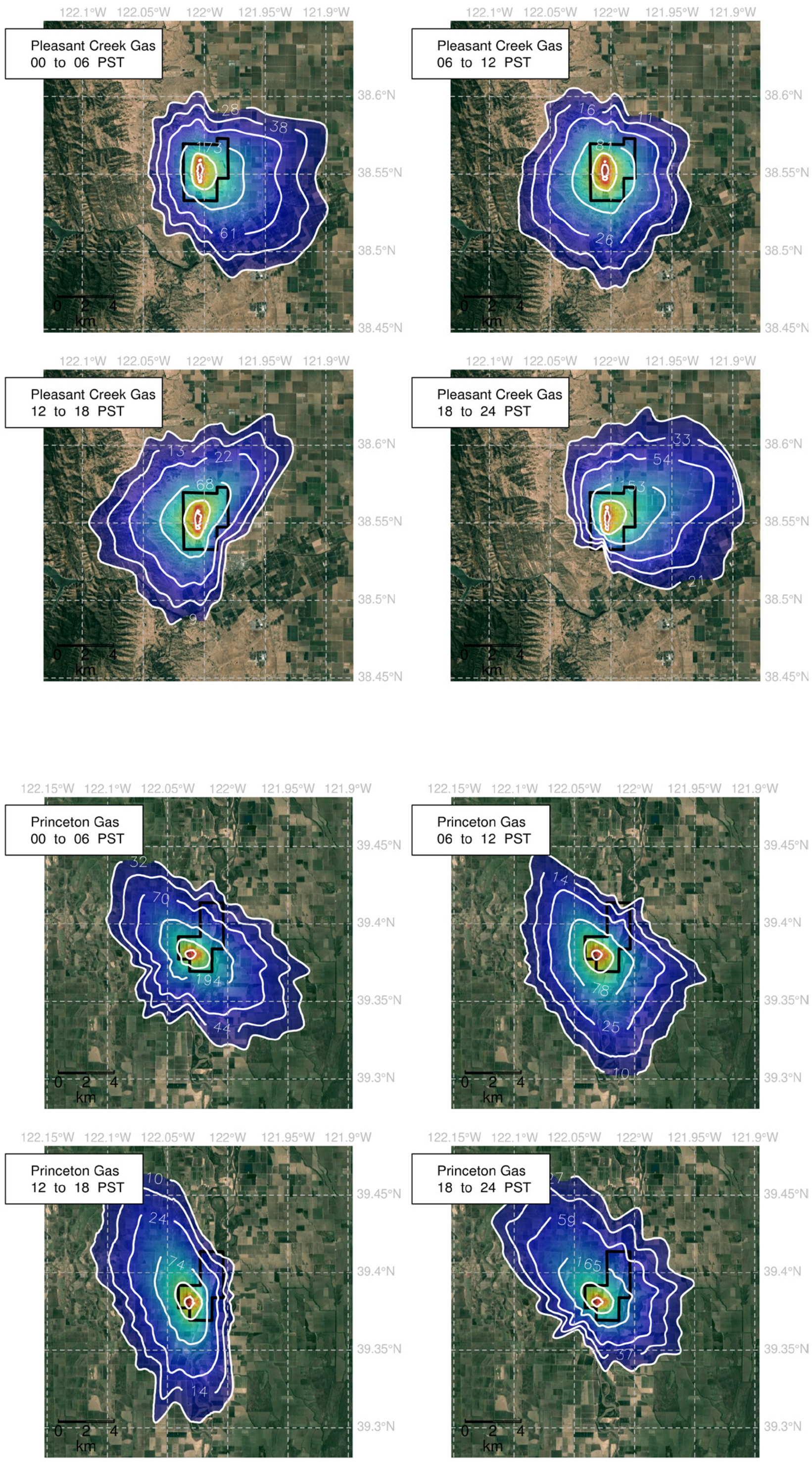


Figure 1.B-25. Mean tracer concentration over flux ratio (ug m^{-3} / ug s^{-1}) scaled by 10^9 at various underground storage facility for the various time bins.

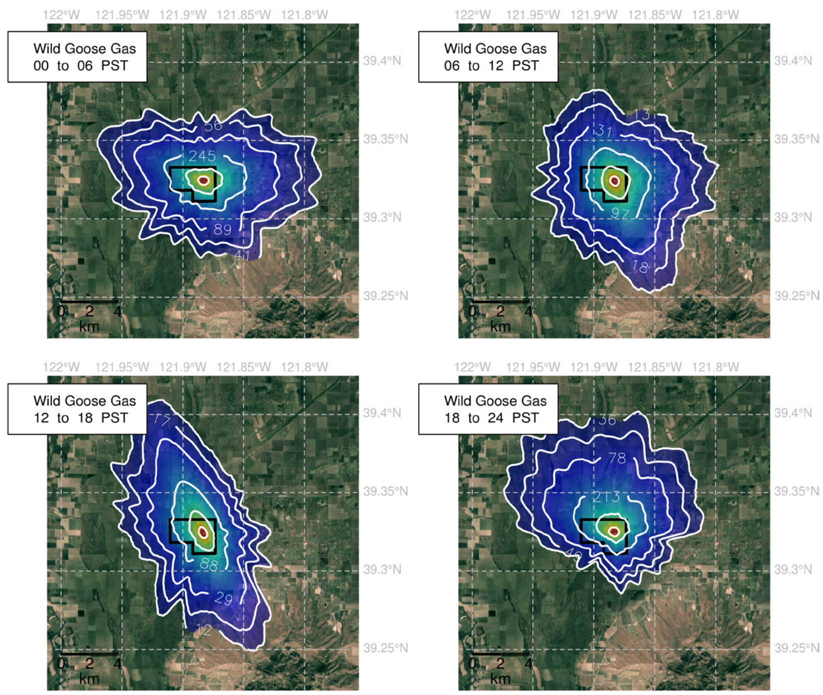


Figure 1.B-26. Mean tracer concentration over flux ratio (ug m^{-3} / ug s^{-1}) scaled by 10^9 at Wild Goose underground storage facility for the various time bins.

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Appendix 1.C: Air Pollutant Emission Inventory Assessment

1.C.1 Tables for Section 1.4.5, Characterization of UGS Facility Emissions

Emissions data were reported to the California Air Resources Board and/or South Coast Air Quality Management District. The data include a list of all chemicals or chemical groupings reported across any or all of the 13 underground gas storage facilities in California from 1987 through 2015. Chemicals are listed from highest to lowest median annual emission by mass (pounds/year). Minimum, maximum, and median emissions are reported to at least one significant digit. Chemicals are reported by name and Chemical Abstract Service Registry Numbers (CASRN). For chemical groupings, Pollutant ID is reported as specified by the Air Toxics Hot Spots Program (AB 2588). Names of chemicals were normalized where possible, and all chemicals were reported with either a CASRN or Pollutant ID. Note: Criteria pollutants reported in tons/year were converted to pounds/year.

Table 1.C-1. Annual emissions by mass (pounds/year) of chemicals reported to emissions inventories for underground gas storage facilities in California between 1987 and 2015.

		Emissions (pounds/year)		
Chemical Name[1,2]	**CASRN[3]**	**Median**	**Min**	**Max**
1,1-Dichloroethane	75-34-3	0.6	0.002	85
1,1,1-Trichloroethane	71-55-6	1.1	1	1
1,1,2-Trichloroethane	79-00-5	2.9	0.003	17
1,2-Dichloropropane	78-87-5	2.4	0.002	15
1,2,4-Trimethylbenzene	95-63-6	69	0.3	325
1,3-Butadiene	106-99-0	57	0.004	244
1,3-Dichloropropene	542-75-6	2.6	0.4	14
2-Methyl naphthalene	91-57-6	6	0.0003	23
2,2,4-Trimethylpentane	540-84-1	21	1	36
Acenaphthene	83-32-9	0.18	0.00002	1
Acenaphthylene	208-96-8	0.9	0.00004	4
Acetaldehyde	75-07-0	392	0	4499
Acrolein	107-02-8	206	0.02	2833
Ammonia	7664-41-7	996	0.1	33907
Anthracene	120-12-7	0.03	0.00001	0.05
Arsenic	7440-38-2	0.0012	0.00001	0.03
Asbestos	1332-21-4	0.002	0.00001	0.01
Benzene	71-43-2	171	0.04	1970
Benzo[a]anthracene	56-55-3	0.018	0.000005	0.02

1 Chemical groupings, removed during analysis and discussion in Section 1.4.6;

2 Chemical grouping, but retained due to available toxicity information;

3 Pollutant ID reported rather than CASRN as assigned in the Air Toxics Hot Spots Program.

Chemical Name[1,2]	CASRN[3]	Emissions (pounds/year) Median	Min	Max
Benzo[a]pyrene	50-32-8	0.0003	0.0000001	0.0004
Benzo[b]fluoranthene	205-99-2	0.024	0.0000001	0.1
Benzo[e]pyrene	192-97-2	0.0559	0.0000003	0.3
Benzo[g,h,i]perylene	191-24-2	0.0558	0.0000004	0.3
Benzo[k]fluoranthene	207-08-9	0.00021	0.0000001	0.0003
Beryllium	7440-41-7	0.00009	0.0001	0.0001
Biphenyl	92-52-4	17.8	5	31
Cadmium	7440-43-9	0.0011	0.00001	0.03
Carbon monoxide	630-08-0	45360	192	838656
Carbon tetrachloride	56-23-5	3.3	0.00003	27
Chlorine	7782-50-5	0.081	0.01	0.4
Chlorobenzene	108-90-7	1.2	0.0002	7
Chlorodifluoromethane	75-45-6	10	10	10
Chloroform	67-66-3	1.92	0.002	16
Chromium	7440-47-3	0.008	0.01	0.01
Chromium (VI)	18540-29-9	0.00007	0.000001	0.002
Chrysene	218-01-9	0.089	0.00001	0.5
Copper	7440-50-8	0.0022	0.0001	213
Diesel engine exhaust, PM	99013	4.1	0.4	1464
Diethylene glycol monobutyl ether	112-34-5	12.9	12.9	12.9
Dipropylene glycol methyl ether	34590-94-8	1.55	2	2
Ethylbenzene	100-41-4	25	0.01	291
Ethylene dibromide	106-93-4	4	0.00004	33
Ethylene dichloride	107-06-2	2.7	0.00002	17
Ethylene glycol	107-21-1	27	11	40
Ethylene glycol monobutyl ether	111-76-2	2.17	1	183
Fluoranthene	206-44-0	0.16	0.00001	1
Fluorene	86-73-7	0.8	0.00002	4
Fluorocarbons (chlorinated)[1]	11043	7.82	1	27
Formaldehyde	50-00-0	3159	0.2	27296
Gasoline vapors[1]	11013	38	38	38
Glycol ethers1	11153	0.8	0.8	1.6
Hexane	110-54-3	250	0.2	7638
Hydrochloric acid	7647-01-0	0.094	0.002	4
Hydrogen sulfide	6/4/83	0.013	0.01	0.4
Indeno[1,2,3-cd]pyrene	193-39-5	0.0004	0.0000001	0.001
Lead	7439-92-1	0.009	0.0001	0.2

1 Chemical groupings, removed during analysis and discussion in Section 1.4.6;

2 Chemical grouping, but retained due to available toxicity information;

3 Pollutant ID reported rather than CASRN as assigned in the Air Toxics Hot Spots Program.

Chemical Name[1,2]	CASRN[3]	Emissions (pounds/year)		
		Median	Min	Max
m-Xylene	108-38-3	190	0.2	801
Manganese	7439-96-5	0.0019	0.0001	7590
Mercury	7439-97-6	0.0008	0.00002	0.04
Methane	74-82-8	0.24	0.02	73
Methanol	67-56-1	213	0.04	1515
Methyl ethyl ketone	78-93-3	0.017	0.001	640
Methyl tert-butyl ether	1634-04-4	0.38	0.02	2
Methylene chloride	75-09-2	10.04	0.0001	48
Naphthalene	91-20-3	24	0.002	106
Nickel	7440-02-0	0.003	0.00001	0.1
Nitrogen oxide	10024-97-2	0.025	0.001	1
Nitrogen oxides (NOX)[1]	426033	35156	220	904200
o-Xylene	95-47-6	0.43	0.01	4
p-Xylene	106-42-3	2.23	1	4
Particulate matter (PM)[1]	111013	870	14	17000
Perylene	198-55-0	0.00024	0.0000001	0.0003
Phenanthrene	85-01-8	1.96	0.00004	7
Phenol	108-95-2	2.02	1	3
Phosphorus	7723-14-0	12.7	3	23
PM10	111013	840	10.3	16889
PM2.5	111013	820	13.9	16852
Polycyclic aromatic hydrocarbons, with components reported (PAHs-w/)[1]	115013	61	4.83	117
Polycyclic aromatic hydrocarbons, without components reported (PAHs-w/o)[1]	11513	0.06	0.0003	28
Propylene	115-07-1	245	7	9608
Propylene oxide	75-56-9	45	28	45
Pyrene	129-00-0	0.2	0.00001	1
Reactive organic gases (ROG)[1]	ROGC3	16310	20	363921
Selenium	7782-49-2	0.001	0.00002	0.05
Silica, crystalline	11753	18.3	18	18
Sodium hydroxide	1310-73-2	4.4	0.04	4
Styrene	100-42-5	1.54	0.002	13
Sulfur oxides (SOX)[1]	42-40-1	152	0.298	20000
Tetrachloroethane	79-34-5	3.6	0.005	22
Perchloroethylene	127-18-4	51	24	277

1 Chemical groupings, removed during analysis and discussion in Section 1.4.6;

2 Chemical grouping, but retained due to available toxicity information;

3 Pollutant ID reported rather than CASRN as assigned in the Air Toxics Hot Spots Program.

Chemical Name[1,2]	CASRN[3]	Emissions (pounds/year)		
		Median	Min	Max
Toluene	108-88-3	198	0.002	2246
Total organic gases (TOG)[1]	431013	101080	29	2954880
Total Suspended Particulates (TSP)[1]	TSP3	11972	11972	11972
Trichloroethylene	79-01-6	44	0.05	102
Vinyl chloride	75-01-4	1.58	0.00001	11
VOCs	VOC3	59146	31168	314682
Xylenes[2]	1330-20-7	72	0.02	893
Zinc	7440-66-6	0.26	0.001	0.47

1 Chemical groupings, removed during analysis and discussion in Section 1.4.6;

2 Chemical grouping, but retained due to available toxicity information;

3 Pollutant ID reported rather than CASRN as assigned in the Air Toxics Hot Spots Program.

1.C.2 Tables for Section 1.4.6, Toxicity of Chemical Components with Public Health Relevance

Toxicity-weighted emissions scores were calculated using all available median annual emissions data (pounds/year) from emissions inventories maintained by California Air Resources Board (CARB) and South Coast Air Quality Management District (SCAQMD) and Inhalation Toxicity Scores for individual chemicals from U.S. EPA's Risk-Screening Environmental Indicators (RSEI) Model (U.S. EPA, 2017). Chemical-specific median annual emissions were multiplied by toxicity weights to calculate toxicity-weighted emissions.

U.S. EPA's Inhalation Toxicity Scores are chemical-specific toxicity weights for chronic non-cancer and cancer endpoints. For chemicals with toxicity weights for both non-cancer and cancer endpoints, the highest (most protective) value was chosen as the Inhalation Toxicity Score (U.S. EPA, 2017).

We also provide calculations that evaluate non-cancer and cancer hazards independently. In brief, non-cancer toxicity weights are derived using U.S. EPA Inhalation reference concentrations (RfC); cancer toxicity weights are derived using U.S. EPA Inhalation Unit Risk (IUR) for individual chemicals. For more information about U.S. EPA's RSEI toxicity weights, see https://www.epa.gov/rsei/rsei-toxicity-data-and-calculations.

Total (non-cancer and cancer), non-cancer, and cancer toxicity-weighted emissions and rankings for pollutants associated with UGS in California are shown in Table 1.C-2.

Table 1.C-2. Total (non-cancer and cancer), non-cancer, and cancer toxicity-weighted emissions for pollutants associated with UGS in California. Pollutants are reported in alphabetical order.

			Inhalation Toxicity Score		Non-cancer		Cancer	
Chemical Name[1]	**CASRN**	**Median annual emissions (pounds/year)**	**Overall Toxicity Weights**	**Toxicity-weighted emissions**	**Non-cancer Toxicity Weights**	**Toxicity-weighted emissions**	**Cancer Toxicity Weights**	**Toxicity-weighted emissions**
2-Methyl naphthalene[1]	91-57-6	6	710,000	4,433,950			710,000	4,260,000
Acenaphthene[1]	83-32-9	0.2	710,000	127,729			710,000	127,800
Acenaphthylene[1]	208-96-8	0.9	710,000	623,337			710,000	639,000
Acetaldehyde	75-07-0	392	7,900	3,093,610	390	152,880	7,900	3,096,800
Acrolein	107-02-8	206	180,000	37,066,065	180,000	37,080,000		
Ammonia	7664-41-7	996	35	34,874	35	34,860		
Anthracene	120-12-7	0.03	3.3	0.1				
Arsenic	7440-38-2	0.001	15,000,000	17,865	230,000	276	15,000,000	18,000
Asbestos	1332-21-4	0.002	165,000,000	324,225			170,000,000	340,000
Benzene	71-43-2	171	28,000	4,791,412	120	20,520	28,000	4,788,000
Benzo(a)pyrene[1]	50-32-8	0.0003	710,000	198			710,000	213
Benzo(g,h,i)perylene	191-24-2	0.06	20,000	1,116			20,000	1,116
Benzo[a]anthracene[1]	56-55-3	0.06	710,000	39,612			710,000	12,780
Benzo[b]fluoranthene[1]	205-99-2	0.02	710,000	16,962			710,000	17,040
Benzo[e]pyrene[1]	192-97-2	0.06	710,000	39,663			710,000	39,689
Benzo[k]fluoranthene[1]	207-08-9	0.0002	710,000	148			710,000	149.1
Beryllium	7440-41-7	0.0001	8,600,000	784	180,000	16.2	8,600,000	774
Biphenyl	92-52-4	18	800	14,271				
1,3-Butadiene	106-99-0	57	110,000	6,236,313	1,800	102,600	110,000	6,270,000
Cadmium	7440-43-9	0.001	6,400,000	6,912	350,000	385	6,400,000	7,040
Carbon tetrachloride	56-23-5	3	21,000	69,689	35	115.5	21,000	69,300
Chlorine	7782-50-5	0.08	23,000	1,867	23,000	1,863		
Chlorobenzene	108-90-7	1	3.5	4	3.5	4.2		
Chlorodifluoromethane	75-45-6	10	0.07	1	0.07	0.7		
Chloroform	67-66-3	2	82,000	157,053	36	69.12	82,000	157,440
Chromium (VI)[2]	7440-47-3	0.008	43,000,000	325,080	35,000	280	43,000,000	344,000
Chrysene[1]	218-01-9	0.09	710,000	63,190			710,000	63,190
Copper	7440-50-8	0.002	1,500	3.4	1,500	3.3		
Ethylene dibromide	106-93-4	4	2,100,000	8,428,974	390	1,560	2,100,000	8,400,000
Ethylene dichloride	107-06-2	3	93,000	251,633	1.5	4.05	93,000	251,100
Methylene chloride	75-09-2	10	36	361	5.8	58.23	36	361.44
1,2-Dichloropropane	78-87-5	2	880	2,145	880	2,112		
1,3-Dichloropropene	542-75-6	2.6	14,000	36,384	180	468	14,000	36,400

1 Polycyclic aromatic hydrocarbon (PAH) toxicity weight applied as specific PAH did not have toxicity weight provided.

2 Chromium (hexavalent) toxicity weight applied to Chromium (VI) emissions. No separate toxicity weight provided for nonhexavalent chromium.

Chemical Name[1]	CASRN	Median annual emissions (pounds/year)	Inhalation Toxicity Score: Overall Toxicity Weights	Inhalation Toxicity Score: Toxicity-weighted emissions	Non-cancer: Non-cancer Toxicity Weights	Non-cancer: Toxicity-weighted emissions	Cancer: Cancer Toxicity Weights	Cancer: Toxicity-weighted emissions
Ethylbenzene	100-41-4	25	890	22,193	3.5	87.5	890	22,250
Ethylene glycol	107-21-1	27	8.8	234	8.8	237.6		
1,1-Dichloroethane	75-34-3	0.6	570	328	7	4.2	570	342
Fluoranthene[1]	206-44-0	0.2	710,000	113,423			710,000	113,600
Fluorene[1]	86-73-7	0.8	710,000	579,379			710,000	568,000
Formaldehyde	50-00-0	3159	46,000	145,310,537	360	1,137,240	46,000	145,314,000
Hexane	110-54-3	250	5	1,252	5	1,250		
Hydrochloric acid	7647-01-0	0.09	180	17	180	16.92		
Hydrogen sulfide	2148878	0.01	1,800	23	1,800	23.4		
Indeno[1,2,3-cd] pyrene[1]	193-39-5	0.0004	710,000	288			710,000	284
Lead	7439-92-1	0.01	23,000	207	23,000	207		
Manganese	7439-96-5	0.002	12,000	23	12,000	22.8		
Mercury	7439-97-6	0.001	12,000	10	12,000	9.6		
Methanol	67-56-1	213	0.18	38	0.18	38.34		
Methyl ethyl ketone	78-93-3	0.02	0.7	0.01	0.7	0.01		
Methyl tert-butyl ether	1634-04-4	0.4	93	35	1.2	0.46	93	35.34
Naphthalene	91-20-3	24	12,000	285,914	1,200	28,800	12,000	288,000
Nickel	7440-02-0	0.003	930,000	3,116	39,000	117	930,000	2,790
Perylene[1]	198-55-0	0.0002	710,000	171			710,000	170.4
Phenanthrene[1]	85-01-8	2	710,000	1,388,760			710,000	710,000
Phenol	108-95-2	2	18	36	18	36.36		
Phosphorus	7723-14-0	13	50,000	636,875	50,000	635,000		
Propylene	115-07-1	245	1.2	294	1.2	294		
Propylene oxide	75-56-9	45	13,000	579,800	120	5,400	13,000	585,000
Pyrene[1]	129-00-0	0.2	710,000	138,969			710,000	142,000
Selenium	7782-49-2	0.001	180	0.2	180	0.18		
Styrene	100-42-5	2	3.5	5	3.5	5.39		
Tetrachloroethane	79-34-5	4	210,000	760,790			210,000	756,000
Perchloroethylene	127-18-4	51	930	47,695	88	4,488	930	47,430
Toluene	108-88-3	198	0.7	139	0.7	138.6		
1,1,1-Trichloroethane	71-55-6	1	0.7	1	0.7	0.77		
1,1,2-Trichloroethane	79-00-5	3	5,700	16,426	8.8	25.52	5,700	16,530
Trichloroethylene	79-01-6	44	15,000	657,075	1,800	79,200	15,000	660,000
1,2,4-Trimethylbenzene	95-63-6	69	580	39,750	580	40,020		
Vinyl chloride	75-01-4	2	31,000	48,999	35	55.3	31,000	48,980

1 Polycyclic aromatic hydrocarbon (PAH) toxicity weight applied as specific PAH did not have toxicity weight provided.

2 Chromium (hexavalent) toxicity weight applied to Chromium (VI) emissions. No separate toxicity weight provided for nonhexavalent chromium.

Chemical Name[1]	CASRN	Median annual emissions (pounds/year)	Inhalation Toxicity Score: Overall Toxicity Weights	Inhalation Toxicity Score: Toxicity-weighted emissions	Non-cancer: Non-cancer Toxicity Weights	Non-cancer: Toxicity-weighted emissions	Cancer: Cancer Toxicity Weights	Cancer: Toxicity-weighted emissions
Xylenes	1330-20-7	72	35	2,522	35	2,520		
Xylene, m-	108-38-3	190	35	6,635	35	6,650		
Xylene, o-	95-47-6	0.4	35	15	35	15.05		
Xylene, p-	106-42-3	2	35	78	35	78.05		
Zinc	7440-66-6	0.3	100	26	100	26		

1 Polycyclic aromatic hydrocarbon (PAH) toxicity weight applied as specific PAH did not have toxicity weight provided.

2 Chromium (hexavalent) toxicity weight applied to Chromium (VI) emissions. No separate toxicity weight provided for nonhexavalent chromium.

Table 1.C-3. Hazard Screening Matrix for Acute Human Health Effects of Chemicals Emitted from UGS Facilities in California (Non-cancer). Chemicals are organized by alphabetical order.

Chemical	CASRN	Acute REL (ug/m3)	Acute MRL (ug/m3)	Acute Screening Criteria (ug/m3)
1,1,1-Trichloroethane	71-55-6	6.80E+04		6.80E+04
1,3-Butadiene	106-99-0	6.60E+02		6.60E+02
Acetaldehyde	75-07-0	4.70E+02		4.70E+02
Acrolein	107-02-8	2.50E+00	6.88E+00	2.50E+00
Ammonia	7664-41-7	3.20E+03	1.18E+03	1.18E+03
Arsenic	7440-38-2	2.00E-01		2.00E-01
Benzene	71-43-2	2.70E+01	2.88E+01	2.70E+01
Carbon monoxide	630-08-0	2.30E+04		2.30E+04
Carbon tetrachloride	56-23-5	1.90E+03		1.90E+03
Chlorine	7782-50-5	2.10E+02		2.10E+02
Chloroform	67-66-3	1.50E+02		1.50E+02
Copper	7440-50-8	1.00E+02		1.00E+02
Ethylene glycol	107-21-1		2.00E+03	2.00E+03
Ethylene glycol monobutyl ether	111-76-2	1.40E+04	4.46E+03	4.46E+03
Formaldehyde	50-00-0	5.50E+01	4.91E+01	4.91E+01
Hydrochloric acid	7647-01-0	2.10E+03		2.10E+03
Hydrogen sulfide	2148878	4.20E+01	9.76E+01	4.20E+01
m-Xylene	108-38-3	2.20E+04		2.20E+04
Methyl tert-butyl ether	1634-04-4		7.21E+03	7.21E+03
Mercury	7439-97-6	6.00E-01		6.00E-01
Methanol	67-56-1	2.80E+04		2.80E+04
Methyl ethyl ketone	78-93-3	1.30E+04		1.30E+04
Methylene chloride	75-09-2	1.40E+04	2.08E+03	2.08E+03
Nickel	7440-02-0	2.00E-01		2.00E-01
o-Xylene	95-47-6	2.20E+04		2.20E+04

Chemical	CASRN	Acute REL (ug/m3)	Acute MRL (ug/m3)	Acute Screening Criteria (ug/m3)
p-Xylene	106-42-3	2.20E+04		2.20E+04
Perchloroethylene	127-18-4	2.00E+04	4.07E+01	4.07E+01
Phenol	108-95-2	5.80E+03		5.80E+03
Propylene oxide	75-56-9	3.10E+03		3.10E+03
Sodium Hydroxide	1310-73-2	8.00E+00		8.00E+00
Styrene	100-42-5	2.10E+04	2.13E+04	2.10E+04
Toluene	108-88-3	3.70E+04	7.54E+03	7.54E+03
Vinyl chloride	75-01-4	1.80E+05		1.80E+05
Xylenes	1330-20-7	2.20E+04	8.68E+03	8.68E+03

References

U.S. EPA (Environmental Protection Agency), 2017. Risk-Screening Environmental Indicators (RSEI) Model - RSEI Toxicity-Data and Calculations. https://www.epa.gov/rsei/rsei-toxicity-data-and-calculations.

1.C.3 Supplementary Tables for Section 1.4.5.1., Characterization of UGS Facility Emissions

California UGS Facility-Specific Emissions reported between 1987 and 2015. Tables 1.C-4 through 1.C-16 report facility-specific annual emissions of pollutants for the 13 UGS facilities in California. Emissions are reported to at least one significant digit.

Table 1.C-4. Annual emissions of pollutants from the Aliso Canyon UGS facility between 1987 and 2015 reported in pounds/year.

Pollutant ID[1]	CASRN[2]	Median	Min	Max	Mean
1,1,2- Trichloroethane	79-00-5	9	5	12	9
1,2-Dichloropropane	78-87-5	7	4	7	7
1,2,4-Trimethylbenzene	95-63-6	193	193	199	195
1,3-Butadiene[1]	106-99-0	121	100	161	129
1,3-Dichloropropene	542-75-6	7	6	7	7
2-Methylnaphthalene	91-57-6	9	6	12	9
Acenaphthene	83-32-9	0.3	0.1	0.5	0.3
Acenaphthylene	208-96-8	1	1	2	1
Acetaldehyde[1]	75-07-0	448	448	2254	1095
Acrolein	107-02-8	175	175	1443	633
Ammonia	7664-41-7	16960	4136	33907	17210
Arsenic	7440-38-2	0.003	0.001	0.006	0.003
Benzene[1]	71-43-2	666	341	1526	858
Benzo[b]fluoranthene	205-99-2	0.04	0.03	0.06	0.04
Benzo[e]pyrene	192-97-2	0.09	0.02	0.15	0.08
Benzo[g,h,i]perylene	191-24-2	0.09	0.02	0.15	0.08
Cadmium	7440-43-9	0.002	0.001	0.01	0.003
Carbon monoxide[1]	630-08-0	296476	182897	478600	307557
Carbon tetrachloride[1]	56-23-5	11	4	15	10
Chlorine	7782-50-5	0.4	0.2	0.4	0.4
Chloroform[1]	67-66-3	8	6	8	7
Chromium (VI)	18540-29-9	0.0001	0	0.0004	0.0001
Chrysene	218-01-9	0.2	0.05	0.3	0.2
Copper	7440-50-8	0.01	0.01	213	43
Diesel engine exhaust, particulate matter (PM)	9901[2]	46	46	46	46
Ethylbenzene[1]	100-41-4	291	260	291	283
Ethylene dibromide	106-93-4	13	5	18	12
Ethylene dichloride	107-06-2	6	3	10	6

1 Compounds with unique chemical identifier (not a pollutant group) and monitored for during or after the Aliso Canyon SS-25 LOC event.

2 Pollutant ID is reported as CASRN was unavailable

Pollutant ID[1]	CASRN[2]	Median	Min	Max	Mean
Ethylene glycol monobutyl ether	111-76-2	1	1	20	6
Fluoranthrene	206-44-0	0.3	0.1	0.4	0.3
Fluorene	86-73-7	1	1	2	1
Formaldehyde[1]	50-00-0	15001	5688	20640	14722
Hexane[1]	110-54-3	471	471	501	479
Hydrochloric acid	7647-01-0	0.24	0.20	0.24	0.23
Lead	7439-92-1	0.013	0.008	0.031	0.015
m-Xylene[1]	108-38-3	801	2	801	601
Manganese	7439-96-5	0.007	0.005	7590	1518
Mercury	7439-97-6	0.0027	0.0027	0.0030	0.0028
Methanol	67-56-1	213	213	937	488
Methyl ethyl ketone[1]	78-93-3	12	4	640	167
Methyl tert-butyl ether	1634-04-4	2.0	0.9	2.0	1.7
Methylene chloride[1]	75-09-2	30	7	48	29
Naphthalene	91-20-3	30	21	81	44
Nickel	7440-02-0	0.01	0.01	0.02	0.01
Nitrogen oxides (NO_x)	42603[1]	371263	294758	817400	397828
o-Xylene[1]	95-47-6	2	1	2	1
PAHs, without components reported	1151[2]	1	1	6	3
Particulate matter (PM)	11101[2]	828	200	17000	4266
Perchloroethylene[1]	127-18-4	60	47	277	111
Phenanthrene	85-01-8	2	2	4	3
PM10	11101[2]	789	190	16889	3931
PM2.5	11101[2]	785	186	16852	3920
Propylene[1]	115-07-1	7590	7590	7590	7590
Propylene oxide[1]	75-56-9	45	45	45	45
Pyrene	129-00-0	0.3	0.1	1	0.3
Reactive organic gases (ROG)	ROGC2	69	21	182	91
Selenium	7782-49-2	0.003018	0.003000	0.003018	0.003014
Styrene[1]	100-42-5	7	4	7	6
Sulfur oxides (SO_x)	42401[2]	3586	3	5559	2935
Toluene[1]	108-88-3	640	640	943	751
Total organic gases (TOG)	43101[1]	727944	139873	2954880	1096665
Total Suspended Particulates (TSP)	TSP1	6	6	6	6
Trichloroethylene[1]	79-01-6	22	0.05	57	27
Vinyl chloride	75-01-4	4	2	6	4
Volatile organic compounds (VOC)	VOC[1]	157	157	157	157
Xylenes	1330-20-7	216	162	893	263

1 Compounds with unique chemical identifier (not a pollutant group) and monitored for during or after the Aliso Canyon SS-25 LOC event.

2 Pollutant ID is reported as CASRN was unavailable

Table 1.C-5. Annual emissions of pollutants from the Princeton Gas UGS facility between 2012 and 2015 reported in pounds/year.

Pollutant ID	CASRN[1]	Median	Min	Max	Mean
Ammonia	7664-41-7	0.06	0.06	0.44	0.155
Carbon monoxide	630-08-0	320	320	4500	1365
Nitrogen oxides (NO_x)	42603[1]	290	290	1592	615.5
Particulate matter (PM)	11101[1]	50	50	68.6	54.65
PM10	11101[1]	50	50	68	54.5
PM2.5	11101[1]	46	44	62	50
Reactive organic gases (ROG)	ROGC[1]	104	104	1352	416
Sulfur oxides (SO_x)	42401[1]	26	26	30	27
Total organic gases (TOG)	43101[1]	118	118	1398	438

1 Pollutant ID is reported as CASRN was unavailable

Table 1.C-6. Annual emissions of pollutants from the Gill Ranch UGS facility between 2012 and 2015 reported in pounds/year.

Pollutant ID	CASRN[1]	Median	Min	Max	Mean
1,1-Dichloroethane	75-34-3	0.002	0.002	0.002	0.002
1,1,2Trichloroethane	79-00-5	0.004	0.003	0.005	0.004
1,2-Dichloropropane	78-87-5	0.0023	0.0023	0.0023	0.0023
1,3-Butadiene	106-99-0	0.12	0.12	0.12	0.12
Acetaldehyde	75-07-0	0.6	0.6	0.7	0.6
Acrolein	107-02-8	0.6	0.5	0.6	0.6
Benzene	71-43-2	0.5	0.5	0.7	0.6
Carbon monoxide	630-08-0	429.2	191.6	765.8	453.9
Carbon tetrachloride	56-23-5	0.003	0.003	0.003	0.003
Chlorobenzene	108-90-7	0.002	0.002	0.002	0.002
Chloroform	67-66-3	0.002	0.002	0.002	0.002
Diesel engine exhaust, particulate matter (PM)	9901[1]	1.8	1.0	1.9	1.6
Ethylbenzene	100-41-4	0.3	0.3	0.5	0.3
Ethylene dibromide	106-93-4	0.004	0.004	0.004	0.004
Ethylene dichloride	107-06-2	0.002	0.002	0.002	0.002
Formaldehyde	50-00-0	4.1	4.1	4.7	4.3
Hexane	110-54-3	0.2	0.2	0.4	0.2
Methane	74-82-8	0.05	0.05	0.05	0.05
Methanol	67-56-1	0.5	0.5	0.5	0.5
Methylene chloride	75-09-2	0.0074	0.0074	0.0074	0.0074
Naphthalene	91-20-3	0.0263	0.0261	0.0350	0.0285

1 Pollutant ID is reported as CASRN was unavailable

Pollutant ID	CASRN[1]	Median	Min	Max	Mean
Nitrogen oxide	10024-97-2	0.0060	0.0060	0.0060	0.0060
Nitrogen oxides (NO_x)	42603	475.1	293.3	684.5	482.0
PAHs, without components reported	1151[1]	0.037	0.037	0.049	0.040
Particulate matter (PM)	11101[1]	284.5	226.5	458.5	313.5
PM10	11101[1]	284.4	226.5	458.4	313.4
PM2.5	11101[1]	284.4	226.4	458.4	313.4
Propylene	115-07-1	19.7	19.2	42.0	25.2
Reactive organic gases (ROG)	ROGC[1]	409.3	322.4	656.8	449.5
Styrene	100-42-5	0.002	0.002	0.002	0.002
Sulfur oxides (SO_x)	42401[1]	103.3	83.1	168.3	114.5
Toluene	108-88-3	1.1	1.1	2.2	1.4
Total organic gases (TOG)	43101[1]	1115.5	826.1	1675.5	1183.1
Vinyl chloride	75-01-4	0.001	0.001	0.001	0.001
Xylenes	1330-20-7	0.8	0.7	1.6	1.0

1 Pollutant ID is reported as CASRN was unavailable

Table 1.C-7. Annual emissions of pollutants from the Goleta UGS facility between 1987 and 2015 reported in pounds/year.

Pollutant ID	CASRN[1]	Median	Min	Max	Mean
1,3-Butadiene	106-99-0	67	0.2	113	56
Acetaldehyde	75-07-0	281	9	476	239
Acrolein	107-02-8	255	5	441	217
Ammonia	7664-41-7	20018	20018	20018	20018
Arsenic	7440-38-2	0.02	0.0003	0.03	0.02
Benzene	71-43-2	414	29	612	336
Cadmium	7440-43-9	0.02	0.00004	0.03	0.01
Carbon monoxide	630-08-0	120090	49600	279320	135084
Carbon tetrachloride	56-23-5	2	1	3	2
Chromium	7440-47-3	0.01	0.007	0.01	0.01
Chromium (VI)	18540-29-9	0.001	0.000003	0.002	0.001
Copper	7440-50-8	0.05	0.0001	0.1	0.04
Chlorobenzene	108-90-7	1	0.0002	2	1
Chloroform	67663	2	1	2	2
Ethylbenzene	100-41-4	5	2	15	6
Ethylene dibromide	106-93-4	2	2	4	3
Formaldehyde	50-00-0	2197	110	3456	1850
Gasoline vapors	1110[1]	38	38	38	38
Hexane	110-54-3	3799	3427	7638	4214
Hydrochloric acid	7647-01-0	2	0.01	4	2

1 Pollutant ID is reported as CASRN was unavailable.

Pollutant ID	CASRN[1]	Median	Min	Max	Mean
Hydrogen sulfide	7783-06-4	0.4	0.4	0.4	0.4
Lead	7439-92-1	0.10	0.0002	0.18	0.08
Manganese	7439-96-5	0.04	0.00008	0.07	0.03
Methanol	67-56-1	319	2	513	266
Mercury	7439-97-6	0.023	0.00005	0.04	0.020
Methylene chloride	75-09-2	5	3	7	5
Naphthalene	91-20-3	10	2	17	9
Nickel	7440-02-0	0.04	0.0001	0.1	0.04
Nitrogen oxides (NO_x)	42603[1]	11144	6600	176600	28335
PAHS, without components reported	1151[1]	15	1	24	14
Particulate matter (PM)	11101[1]	1629	660	3400	1741
PM10	11101[1]	1622	656	3382	1731
PM2.5	11101[1]	1619	655	3376	1729
Propylene	115-07-1	242	7	1123	251
Reactive organic gases (ROG)	ROGC1	88216	15125	292458	91400
Selenium	7782-49-2	0.03	0.00006	0.05	0.02
Styrene	100-42-5	1	1	2	1
Sulfur oxides (SO_x)	42401[1]	172	0	20000	1401
Toluene	108-88-3	1104	11	2246	784
Total organic gases (TOG)	43101[1]	240972	101080	469323	232550
Xylenes	1330-20-7	428	6	886	305
Zinc	7440-66-6	0.3	0.0006	0.5	0.2

1 Pollutant ID is reported as CASRN was unavailable.

Table 1.C-8. Annual emissions of pollutants from the Honor Rancho UGS facility between 1987 and 2015 reported in pounds/year.

Pollutant ID	CASRN[1]	Median	Min	Max	Mean
1,1,1-Trichloroethane	71-55-6	1	1	1	1
1,1,2-Trichloroethane	79-00-5	17	13	22	17
1,2-Dichloropropane	78-87-5	10	10	15	11
1,2,4-Trimethylbenzene	95-63-6	70	70	81	72
1,3-Butadiene	106-99-0	184	144	244	184
1,3-Dichloropropene	542-75-6	11	11	14	12
2-Methylnaphthalene	91-57-6	16	12	23	16
Acenaphthene	83-32-9	1	0.1	1	1
Acenaphthylene	208-96-8	3	1	4	2
Acetaldehyde	75-07-0	546	546	4499	2012

1 Pollutant ID is reported as CASRN was unavailable.

Pollutant ID	CASRN[1]	Median	Min	Max	Mean
Acrolein	107-02-8	216	216	2833	1204
Ammonia	7664-41-7	1863	1401	2476	1889
Arsenic	7440-38-2	0.00001	0	0.0004	0.0001
Benzene	71-43-2	498	396	1889	931
Benzo[b]fluoranthene	205-99-2	0.07	0.01	0.12	0.07
Benzo[e]pyrene	192-97-2	0.18	0.03	0.29	0.16
Benzo[g,h,i]perylene	191-24-2	0.18	0.03	0.29	0.16
Cadmium	7440-43-9	0.00001	0	0.00033	0.00005
Carbon monoxide	630-08-0	220236	21349	403000	221726
Carbon tetrachloride	56-23-5	19	14	27	19
Chlorinated fluorocarbons	1104[1]	8	1	27	8
Chlorine	7782-50-5	0.01	0.01	0.05	0.02
Chloroform	67-66-3	12	12	16	13
Chromium (VI)	18540-29-9	0.000001	0	0.000014	0.000003
Chrysene	218-01-9	0.3	0.1	0.5	0.3
Copper	7440-50-8	0.0003	0.0002	0.0067	0.0014
Diethylene glycol mono-n-butyl ether	112-34-5	13	13	13	13
Diesel engine exhaust, particulate matter	9901[1]	2	2	2	2
Ethylene glycol butyl ether	111-76-2	93	3	183	93
Ethylbenzene	100-41-4	97	97	114	100
Ethylene dibromide	106-93-4	23	17	33	23
Ethylene dichloride	107-06-2	12	9	17	12
Fluoranthene	206-44-0	1	0.1	1	0.5
Fluorene	86-73-7	3	1	4	3
Formaldehyde	50-00-0	18675	983	27296	16744
Glycol ethers	11151	0.4	0.04	1	0.4
Hexane	110-54-3	502	502	655	546
Hydrochloric acid	7647-01-0	0.009	0.002	0.009	0.007
Lead	7439-92-1	0.001	0	0.060	0.008
m-Xylene	108-38-3	0.19	0.19	314	53
Manganese	7439-96-5	0.00029	0.00020	0.00043	0.00030
Mercury	7439-97-6	0.00010	0.00002	0.00010	0.00007
Methanol	67-56-1	1177	1177	1515	1281
Methyl ethyl ketone	78-93-3	0.003	0.003	0.33	0.06
Methyl tert-butyl ether	1634-04-4	0.08	0.08	0.24	0.13
Methylene chloride	75-09-2	13	10	18	14
Naphthalene	91-20-3	47	34	92	59
Nickel	7440-02-0	0.0002	0	0.0034	0.0007
Nitrogen oxides (NO_x)	42603	103638	69764	904200	149268

1 Pollutant ID is reported as CASRN was unavailable.

Pollutant ID	CASRN[1]	Median	Min	Max	Mean
o-Xylene	95-47-6	0.06	0.06	4	1
p-Xylene	106-42-3	2	1	4	2
Polycyclic aromatic hydrocarbons (PAHs), without components reported	1151[1]	0.003	0.001	10	3
Particulate matter (PM)	111011	672	59	7722	2169
Perchloroethylene	127-18-4	51	24	142	59
Phenanthrene	85-01-8	5	3	7	5
Phosphorus	7723-14-0	13	3	23	13
PM10	11101[1]	653	40	7676	2148
PM2.5	111011	646	40	7661	2140
Propylene	115-07-1	9333	9333	9333	9333
Pyrene	129-00-0	1	0.1	1	1
Reactive organic gases (ROG)	ROGC[1]	99532	26067	225650	123576
Selenium	7782-49-2	0.00011	0.00002	0.00011	0.00008
Silica, Crystalline	1175[1]	18	18	18	18
Sodium hydroxide	1310-73-2	4	0	4	4
Styrene	100-42-5	10	10	13	11
Sulfur oxides (SO_x)	42401[1]	272	2	465	246
Toluene	108-88-3	637	395	637	535
Total organic gases (TOG)	43101[1]	718466	94862	2237980	881998
Trichloroethylene	79-01-6	64	8	78	58
Vinyl chloride	75-01-4	8	5	11	7
Volatile organic compounds (VOCs)	VOC[1]	60445	59146	61744	60445
Xylenes	1330-20-7	234	110	384	279

1 Pollutant ID is reported as CASRN was unavailable.

Table 1.C-9. Annual emissions of pollutants from the Lodi Gas UGS facility between 2003 and 2015 reported in pounds/year.

Pollutant ID	CASRN[1]	Median	Min	Max	Mean
1,1-Dichloroethane	75-34-3	0.6	0.6	0.6	0.6
1,1,2-Trichloroethane	79-00-5	0.9	0.8	1.0	0.9
1,2-Dichloropropane	78-87-5	0.7	0.7	0.7	0.7
1,2,4-Trimethylbenzene	95-63-6	0.3	0.3	0.3	0.3
1,3-Butadiene	106-99-0	6.5	6.5	6.5	6.5
2-Methylnaphthalene	91-57-6	0.8	0.8	6.1	2.1
2,2,4-Trimethylpentane	540-84-1	6.1	0.8	6.1	4.8

1 Pollutant ID is reported as CASRN was unavailable.

Pollutant ID	CASRN[1]	Median	Min	Max	Mean
Acenaphthene	83-32-9	0.03	0.03	0.03	0.03
Acenaphthylene	208-96-8	0.1	0.1	0.1	0.1
Acetaldehyde	75-07-0	204	1	204	117
Acrolein	107-02-8	125	3	125	73
Ammonia	7664-41-7	778	103	1200	674
Benzene	71-43-2	12	12	36	21
Benzo[b]fluoranthene	205-99-2	0.004	0.004	0.004	0.004
Benzo[e]pyrene	192-97-2	0.01	0.01	0.01	0.01
Benzo[g,h,i]perylene	191-24-2	0.01	0.01	0.01	0.01
Biphenyl	92-52-4	5.2	5.2	5.2	5.2
Carbon monoxide	630-08-0	21188	598	26664	17795
Carbon tetrachloride	56-23-5	0.9	0.9	0.9	0.9
Chlorobenzene	108-90-7	0.7	0.7	0.7	0.7
Chloroform	67-66-3	0.7	0.7	0.7	0.7
Chrysene	218-01-9	0.02	0.02	0.02	0.02
Ethylbenzene	100-41-4	6	6	122	53
Ethylene dibromide	106-93-4	1.1	1.1	1.1	1.1
Ethylene dichloride	107-06-2	0.6	0.6	0.6	0.6
Fluoranthene	206-44-0	0.03	0.03	0.03	0.03
Fluorene	86-73-7	0.1	0.1	0.1	0.1
Formaldehyde	50-00-0	1291	3	1291	740
Hexane	110-54-3	27	27	280	129
Hydrogen sulfide	6/4/83	0.010	0.006	0.014	0.010
Methane	74-82-8	0.2	0.2	0.3	0.2
Methanol	67-56-1	61.0	61.0	61.0	61.0
Methylene chloride	75-09-2	0.5	0.5	0.5	0.5
Naphthalene	91-20-3	1.9	1.9	55.6	23.5
Nickel	7440-02-0	0.02	0.02	0.02	0.02
Nitrogen oxide	10024-97-2	0.027	0.025	0.7	0.1
Nitrogen oxides (NO_x)	42603[1]	7459	263	11492	7357
Polycyclic aromatic hydrocarbons (PAHs), with components reported	1150[1]	5.4	4.8	5.6	5.3
PAHs, without components reported	1151[1]	0.4	0.0	0.7	0.4
Particulate matter (PM)	11101[1]	8120	20	10167	7224
Phenanthrene	85-01-8	0.3	0.3	0.3	0.3
Phenol	108-95-2	0.6	0.6	0.6	0.6
PM10	11101[1]	8072	10	10047	7145
PM2.5	11101[1]	8055	20	10019	7127
Propylene	115-07-1	8	8	57	27
Pyrene	129-00-0	0.03	0.03	0.03	0.03

1 Pollutant ID is reported as CASRN was unavailable.

Pollutant ID	CASRN[1]	Median	Min	Max	Mean
Reactive organic gases (ROG)	ROGC[1]	3202	152	3962	2722
Styrene	100-42-5	0.6	0.6	0.6	0.6
Sulfur oxides (SO_x)	42401[1]	534	3	698	494
Toluene	108-88-3	11	7	11	9
Total organic gases (TOG)	43101[1]	33006	340	42806	27407
Vinyl chloride	75-01-4	0.4	0.4	0.4	0.4
Xylenes	1330-20-7	5	5	13	8

1 Pollutant ID is reported as CASRN was unavailable.

Table 1.C-10. Annual emissions of pollutants from the Kirby Hills UGS facility between 2008 and 2015 reported in pounds/year.

Pollutant ID	CASRN[1]	Median	Min	Max	Mean
Arsenic	7440-38-2	0	0	0.0002	0.0001
Benzene	71-43-2	12	9	23	13
Beryllium	7440-41-7	0	0	0.00010	0.00003
Cadmium	7440-43-9	0	0	0.00041	0.00013
Carbon monoxide	630-08-0	14054	7629	19622	14177
Chromium (VI)	18540-29-9	0	0	0.00001	0.000003
Formaldehyde	50-00-0	108	76	205	115
Lead	7439-92-1	0	0	0.0003	0.0001
Manganese	7439-96-5	0.001	0	0.001	0.001
Mercury	7439-97-6	0	0	0.0001	0.00004
Methane	74-82-8	54	47	56	52
Nickel	7440-02-0	0.006	0.004	0.007	0.006
Nitrogen oxide	10024-97-2	0.002	0.001	0.003	0.002
Nitrogen oxides (NO_x)	42603[1]	2264	664	3871	2323
Particulate matter (PM)	11101[1]	4257	1436	6050	3988
PM10	11101[1]	4257	1427	6014	3972
PM2.5	11101[1]	4257	1425	6002	3966
Reactive organic gases (ROG)	ROGC[1]	10138	3299	14918	9960
Sulfur oxides (SO_x)	42401[1]	103	60	136	97
Toluene	108-88-3	0.04	0.002	0.07	0.04
Total organic gases (TOG)	43101[1]	114865	56626	162686	112538

1 Pollutant ID is reported as CASRN was unavailable.

Table 1.C-11. Annual emissions of pollutants from the Los Medanos UGS facility between 1987 and 2015 reported in pounds/year.

Pollutant ID	CASRN[1]	Median	Min	Max	Mean
Benzene	71-43-2	7	1	9	6
Carbon monoxide	630-08-0	55681	896	83000	52847
Ethylbenzene	100-41-4	0.01	0.01	0.01	0.01
Ethylene glycol	107-21-1	27	11	40	26
Formaldehyde	50-00-0	4968	394	7204	4597
Methane	74-82-8	58	54	73	62
Nitrogen oxide	10024-97-2	0.0264	0.0260	0.0280	0.0268
Nitrogen oxides (NO_x)	42603[1]	66620	1280	321200	72131
Particulate matter (PM)	11101[1]	790	16	1200	662
PM10	11101[1]	787	16	1193	659
PM2.5	11101[1]	785	16	1190	657
Reactive organic gases (ROG)	ROGC[1]	4150	1869	21869	7386
Sulfur oxides (SO_x)	42401[1]	59	0	960	125
Toluene	108-88-3	0.2	0.1	1	0.3
Total organic gases (TOG)	43101[1]	16472	3574	663683	69128
Xylenes	1330-20-7	0.02	0.02	0.02	0.02

1 Pollutant ID is reported as CASRN was unavailable.

Table 1.C-12. Annual emissions of pollutants from the McDonald Island UGS facility between 1993 and 2015 reported in pounds/year.

Pollutant ID	CASRN[1]	Median	Min	Max	Mean
1,1-Dichloroethane	75-34-3	5.4	5.4	5.4	5.4
1,1,2-Trichloroethane	79-34-5	8.7	7.2	10.2	8.7
1,2-Dichloropropane	78-87-5	6.1	6.1	6.1	6.1
1,2,4-Trimethylbenzene	95-63-6	2.1	2.1	2.1	2.1
1,3-Butadiene	106-99-0	154	154	154	154
2-Methylnaphthalene	91-57-6	4.8	4.8	4.8	4.8
2,2,4-Trimethylpentane	540-84-1	36	36	36	36
Acenaphthene	83-32-9	0.2	0.2	0.2	0.2
Acenaphthylene	208-96-8	0.8	0.8	0.8	0.8
Acetaldehyde	75-07-0	1688	1	1688	965
Acrolein	107-02-8	1197	3	1197	685
Benzene	71-43-2	31.6	0.04	338.2	132.0
Benzo[b]fluoranthene	205-99-2	0.02	0.02	0.02	0.02
Benzo[e]pyrene	192-97-2	0.1	0.1	0.1	0.1

1 Pollutant ID is reported as CASRN was unavailable.

Pollutant ID	CASRN[1]	Median	Min	Max	Mean
Benzo[g,h,i]perylene	191-24-2	0.1	0.1	0.1	0.1
Biphenyl	92-52-4	30.5	30.5	30.5	30.5
Carbon monoxide	630-08-0	83221	3742	208863	89185
Carbon tetrachloride	56-23-5	8.4	8.4	8.4	8.4
Chlorobenzene	108-90-7	6.6	6.6	6.6	6.6
Chloroform	67-66-3	6.5	6.5	6.5	6.5
Chrysene	218-01-9	0.1	0.1	0.1	0.1
Diesel engine exhaust, particulate matter (PM)	9901[1]	12	0	1464	218
Ethylbenzene	100-41-4	10	10	125	56
Ethylene dibromide	106-93-4	10	10	10	10
Ethylene dichloride	107-06-2	5.4	5.4	5.4	5.4
Fluoranthene	206-44-0	0.2	0.2	0.2	0.2
Fluorene	86-73-7	0.8	0.8	0.8	0.8
Formaldehyde	50-00-0	11163	2	11163	6380
Hexane	110-54-3	160	160	288	206
Methane	74-82-8	0.02	0.02	0.02	0.02
Methanol	67-56-1	936	892	1107	967
Methylene chloride	75-09-2	10	10	10	10
Naphthalene	91-20-3	27.6	27.6	57.2	38.6
Nitrogen oxide	10024-97-2	0.004	0.004	0.004	0.004
Nitrogen oxides (NO_x)	42603[1]	40310	3578	92620	41609
Polycyclic aromatic hydrocarbons (PAHs), with components reported	1150[1]	5.1	5.1	5.7	5.3
PAHs, without components reported	1151[1]	28.4	0.01	28.4	22.7
Particulate matter (PM)	11101[1]	1993	104	3844	1743
Phenanthrene	85-01-8	1.5	1.5	1.5	1.5
Phenol	108-95-2	3.5	3.5	3.5	3.5
PM10	11101[1]	1982	104	3678	1686
PM2.5	11101[1]	1978	104	3820	1730
Propylene	115-07-1	16	16	72	32
Pyrene	129-00-0	0.2	0.2	0.2	0.2
Reactive organic gases (ROG)	ROGC[1]	4173	46	19479	8733
Styrene	100-42-5	5.5	5.5	5.5	5.5
Sulfur oxides (SO_x)	42401[1]	544	0	16085	1213
Toluene	108-88-3	7	1	157	60
Total organic gases (TOG)	43101[1]	40204	107	194536	90965
Vinyl chloride	75-01-4	3.4	3.4	3.4	3.4
Xylenes	1330-20-7	12	0.4	61	26

1 Pollutant ID is reported as CASRN was unavailable.

Table 1.C-13. Annual emissions of pollutants from the Montebello UGS facility between 1987 and 2015 reported in pounds/year.

Pollutant ID	CASRN[1]	Median	Min	Max	Mean
1,1,2-Trichloroethane	79-34-5	0.2	0	0.7	0.3
1,2-Dichloropropane	78-87-5	0.2	0	0.4	0.2
1,2,4-Trimethylbenzene	95-63-6	27.2	19.8	34.6	27.2
1,3-Butadiene	106-99-0	0.1	0.004	19.8	3.0
1,3-Dichloropropene	542-75-6	0.2	0	0.4	0.2
2-Methylnaphthalene	91-57-6	0.0003	0.0003	0.0005	0.0004
Acenaphthene	83-32-9	0.00002	0.00002	0.00004	0.00002
Acenaphthylene	208-96-8	0.00004	0.00004	0.0002	0.0001
Acetaldehyde	75-07-0	321	0.05	559	300
Acrolein	107-02-8	151	0.02	224	131
Ammonia	7664-41-7	67	12	183	74
Anthracene	120-12-7	0.00001	0.00001	0.00015	0.00006
Asbestos	1332-21-4	0.0003	0.00003	0.006	0.002
Benzene	71-43-2	66.2	0.1	1969.8	531.5
Benzo[a]anthracene	56-55-3	0.000005	0.000005	0.00004	0.00002
Benzo[a]pyrene	50-32-8	0.0000001	0.0000001	0.00001	0.000003
Benzo[b]fluoranthene	205-99-2	0.0000001	0.0000001	0.00001	0.000004
Benzo[e]pyrene	192-97-2	0.0000003	0.0000003	0.00002	0.00001
Benzo[g,h,i]perylene	191-24-2	0.0000004	0.0000004	0.00001	0.000003
Benzo[k]fluoranthene	207-08-9	0.0000001	0.0000001	0.00001	0.000004
Carbon monoxide	630-08-0	1741	193	838656	177302
Carbon tetrachloride	56-23-5	0.0001	0	0.5	0.1
Chlorine	7782-50-5	0.07	0.01	0.14	0.07
Chloroform	67-66-3	0.2	0	0.4	0.2
Chrysene	218-01-9	0.00001	0.00001	0.00004	0.00002
Copper	7440-50-8	0.0005	0	0.001	0.0005
Ethylbenzene	100-41-4	33	25	41	33
Ethylene dibromide	106-93-4	0.00008	0	0.6	0.1
Ethylene dichloride	107-06-2	0.00004	0	0.3	0.1
Fluoranthene	206-44-0	0.00001	0.00001	0.0	0.0
Fluorene	86-73-7	0.00002	0.00002	0.0	0.0
Formaldehyde	50-00-0	0.9	0.2	19242	4875
Hexane	110-54-3	36	26	46	36
Indeno[1,2,3-cd]pyrene	193-39-5	0.0000001	0.0000001	0.0000057	0.000002
m-Xylene	108-38-3	120	83	156	120
Manganese	7439-96-5	0.0	0	0.0	0.0
Methanol	67-56-1	45	0.04	90	45

1 Pollutant ID is reported as CASRN was unavailable.

Pollutant ID	CASRN[1]	Median	Min	Max	Mean
Methyl ethyl ketone	78-93-3	0.011	0.003	0.02	0.011
Methyl tert-butyl ether	1634-04-4	0.3	0.1	0.6	0.3
Methylene chloride	75-09-2	0.0001	0	41	3
Naphthalene	91-20-3	0.1	0.002	106	32
Nickel	7440-02-0	0.00007	0	0.001	0.0002
Nitrogen oxides (NO_x)	42603	1253	220	428400	60413
o-Xylene	95-47-6	0.3	0.1	0.5	0.3
Polycyclic aromatic hydrocarbons (PAHs), with components reported	1150[1]	117	117	117	117
PAHs, without components reported	1151[1]	0.0004	0	0.006	0.001
Particulate matter (PM)	11101[1]	42	0	1364	372
Perylene	198-55-0	0.0000001	0.0000001	0.000003	0.000001
Phenanthrene	85-01-8	0.00004	0.00004	0.0007	0.0003
PM10	11101[1]	42	0	1356	368
PM2.5	11101[1]	42	0	1353	368
Propylene	115-07-1	9608	9608	9608	9608
Pyrene	129-00-0	0.00001	0.00001	0.0001	0.0001
Reactive organic gases (ROG)	ROGC1	14934	320	206671	36315
Styrene	100-42-5	0.2	0.006	0.4	0.2
Sulfur oxides (SO_x)	424011	3.1	0	6000	505
Toluene	108-88-3	386	78	660	378
Total organic gases (TOG)	431011	27105	400	1241000	194128
Vinyl chloride	75-01-4	0.00003	0	0.2	0.0
Xylenes	1330-20-7	123	0.04	240	121

1 Pollutant ID is reported as CASRN was unavailable.

Table 1.C-14. Annual emissions of pollutants from the Playa del Rey UGS facility between 1987 and 2015 reported in pounds/year.

Pollutant ID	CASRN[1]	Median	Min	Max	Mean
1,1-Dichloroethane	75-34-3	85	85	85	85
1,1,2-Trichloloethane	79-00-5	3	1	4	3
1,2-Dichloropropane	78-87-5	2	1	3	2
1,2,4-Trimethylbenzene	95-63-6	69	66	325	178
1,3-Butadiene	106-99-0	45	24	53	43
1,3-Dichloropropene	542-75-6	2	0.4	3	2
2-Methylnaphthalene	91-57-6	1.14	0.01	1.4	1.01
Acenaphthene	83-32-9	0.07	0.02	0.4	0.1
Acenaphthylene	208-96-8	0.17	0.05	0.20	0.15
Acetaldehyde	75-07-0	383	168	497	308

1 Pollutant ID is reported as CASRN was unavailable.

Pollutant ID	CASRN[1]	Median	Min	Max	Mean
Acrolein	107-02-8	67	5	498	184
Ammonia	7664-41-7	925	182	5110	1405
Anthracene	120-12-7	0.04	0.009	0.05	0.03
Arsenic	7440-38-2	0.001	0.00002	0.005	0.001
Asbestos	1332-21-4	0.0001	0	0.009	0.002
Benzene	71-43-2	172	113	682	319
Benzo[a]anthracene	56-55-3	0.018	0.009	0.02	0.018
Benzo[a]pyrene	50-32-8	0.0003	0	0.0004	0.0002
Benzo[b]fluoranthene	205-99-2	0.0004	0	0.001	0.0003
Benzo[e]pyrene	192-97-2	0.0012	0	0.0015	0.00096
Benzo[g,h,i]perylene	191-24-2	0.001	0	0.002	0.001
Benzo[k]fluoranthene	207-08-9	0.0002	0	0.0003	0.0002
Cadmium	7440-43-9	0.001	0.00002	0.005	0.001
Carbon monoxide	630-08-0	4328	1348	152200	19507
Carbon tetrachloride	56-23-5	3	1	4	3
Chlorine	7782-50-5	0.12	0.01	0.4	0.104
Chloroform	67-66-3	2	1	3	2
Chromium (VI)	18540-29-9	0.00002	0	0.0003	0.00007
Chrysene	218-01-9	0.04	0.009	0.04	0.03
Chlorodifluoromethane	75-45-6	10	10	10	10
Copper	7440-50-8	0.002	0.001	0.003	0.002
Diesel engine exhaust, particulate matter (PM)	9901[1]	11	11	11	11
Dipropylene glycol mono ethyl	34590-94-8	2	2	2	2
Ethylbenzene	100-41-4	80	72	129	84
Ethylene dibromide	106-93-4	4	1	5	3
Ethylene dichloride	107-06-2	2	1	3	2
Fluoranthene	206-44-0	0.020	0.011	0.023	0.019
Fluorene	86-73-7	0.09	0.01	0.11	0.07
Formaldehyde	50-00-0	3038	80	5772	3180
Glycol ethers	11151	2	2	2	2
Hexane	110-54-3	104	99	380	138
Hydrochloric acid	7647-01-0	0.06	0.004	0.09	0.06
Indeno[1,2,3-cd]pyrene	193-39-5	0.0004	0	0.001	0.0004
Lead	7439-92-1	0.004	0.0001	0.03	0.01
m-Xylene	108-38-3	247	223	265	250
Manganese	7439-96-5	0.002	0.001	0.003	0.002
Mercury	7439-97-6	0.0007	0.00004	0.001	0.001
Methanol	67-56-1	130	123	160	132
Methyl ethyl ketone	78-93-3	0.02	0.001	0.05	0.02

1 Pollutant ID is reported as CASRN was unavailable.

Pollutant ID	CASRN[1]	Median	Min	Max	Mean
Methyl tert-butyl ether	1634-04-4	1	0.02	2	0.5
Methylene chloride	75-09-2	17	5	46	19
Naphthalene	91-20-3	5	3	6	5
Nickel	7440-02-0	0.002	0.0001	0.01	0.004
Nitrogen oxides (NO_x)	42603	52321	25714	874600	104402
o-Xylene	95-47-6	0.4	0.01	1	0.4
Polycyclic aromatic hydrocarbons (PAHs), without components reported	1151[1]	0.01	0.001	0.1	0.02
Particulate matter (PM)	11101[1]	1260	0	9400	1414
Perylene	198-55-0	0.0002	0	0.0003	0.0002
Phenanthrene	85-01-8	0.18	0.03	0.23	0.15
PM10	11101[1]	1253	0	5734	1254
PM2.5	11101[1]	1250	0	5217	1230
Propylene	115-07-1	2884	2884	2884	2884
Pyrene	129-00-0	0.03	0.02	0.04	0.03
Reactive organic gases (ROG)	ROGC[1]	38034	15529	177918	47682
Selenium	7782-49-2	0.0007	0.00005	0.001	0.0007
Styrene	100-42-5	3	1	4	2
Sulfur oxides (SO_x)	42401[1]	28	0	400	50
Toluene	108-88-3	214	198	741	252
Total organic gases (TOG)	43101[1]	113054	45106	747800	188502
Trichloroethylene	79-01-6	58	8	102	55
Vinyl chloride	75-01-4	1	0.4	2	1
Volatile organic compounds (VOC)	VOC[1]	32645	31168	34122	32645
Xylenes	1330-20-7	17	9	72	38

1 Pollutant ID is reported as CASRN was unavailable.

Table 1.C-15. Annual emissions of pollutants from the Pleasant Creek UGS facility between 1998 and 2015 reported in pounds/year.

Pollutant ID	CASRN	Median	Min	Max	Mean
Carbon monoxide	630-08-0	6240	4900	22980	7696
Nitrogen oxides (NO_x)	42603[1]	1920	780	33080	6108
Particulate matter (PM)	11101[1]	60	40	161	86
PM10	11101[1]	60	40	160	86
PM2.5	11101[1]	60	34	160	83
Reactive organic gases (ROG)	ROGC[1]	800	20	1700	860
Sulfur oxides (SO_x)	42401[1]	80	60	200	112
Total organic gases (TOG)	43101[1]	5159	29	13499	7415

1 Pollutant ID is reported as CASRN was unavailable.

Table 1.C-16. Annual emissions of pollutants from the Wild Goose UGS facility between 2005 and 2015 reported in pounds/year.

Pollutant ID	CASRN[1]	Median	Min	Max	Mean
Ammonia	7664-41-7	926000	926000	19838000	5298000
Carbon monoxide	630-08-0	12440	9020	19220	12596
Diesel engine exhaust, particulate matter (PM)	9901[1]	2700	2700	12720	5563
Nitrogen oxides (NO_x)	42603[1]	11140	6020	14140	9871
Particulate matter (PM)	11101[1]	5311	754	9082	4364
PM10	11101[1]	3240	460	5540	2662
PM2.5	11101[1]	2948	419	5040	2422
Reactive organic gases (ROG)	ROGC[1]	2740	2140	3880	2849
Total organic gases (TOG)	43101[1]	3880	2140	7247	4898

1 Pollutant ID is reported as CASRN was unavailable.

Appendix 1.D. Human Population Proximity analysis

1.D.1 Overview

Methods

Storage well inventory

We obtained data for California wells from the California Division of Oil, Gas, and Geothermal Resources (DOGGR) using their dataset titled “All Wells.” We intentionally used an older well dataset from 2015 (DOGGR, 2015; see reference list at end of this appendix) to reflect storage-well conditions before the incident at Aliso Canyon that started in October 2015. This was done with the goal of exploring the state of gas storage wells in California before changes brought on by the 2015 Aliso Canyon incident went into effect, including issuance of emergency regulations that would likely make 2016 and later well data unrepresentative of business as usual. We included all well data covering the 10-year time period up to dataset’s end, which included years 2006–2015.

We categorized wells as either ”open” or ”closed” to evaluate the likelihood of a well acting as a conduit for underground gas to reach the surface. This distinction is based on the presence or absence of an unplugged well. An “open” status reflects wells that have been drilled and completed, but have not been plugged. These correspond to well status values of “Active,” “Idle,” or “Buried” in DOGGR’s records (DOGGR, 2014), and include both wells that are currently being used as well as abandoned wells. A ”closed” status reflects all other wells, these either being wells that have been plugged, wells that were never drilled and completed in the first place, or wells with unknown status. In DOGGR’s records, these correspond to well status values of “Plugged,” “New,” “Cancelled,” or “Unknown” (DOGGR, 2014). We chose to include unplugged abandoned wells, but exclude plugged wells, because the literature to date suggests that while plugged wells can leak, they generally have leak rates that are significantly smaller than unplugged abandoned wells (Townsend-Small et al., 2016; Kang et al., 2016). Wells that were never spudded do not present any leakage pathways and thus pose no risk of gas migration.

To examine the risk of public health risks from multiple angles, we split the well dataset into two partially overlapping datasets which we labeled Tier 1 and Tier 2.

The Tier 1 dataset is focused specifically on the storage pool around each underground gas storage facility. It includes any open well that is located within a gas storage pool, defined as any pool into which gas was injected via a well with DOGGR’s GS type designation indicating a gas storage injector or producer well (DOGGR, 2014), and determined through examination of annual injection databases (DOGGR, 2017). Since the wells within the Tier 1 designation are drilled directly into the gas storage pool, they post the most likely conduit for gas from the storage pool to migrate to the earth’s surface. A loss of wellbore integrity is the most common cause of unintended gas migration, with common causes including casing failure or cement failure (Ingraffea et al., 2014; Davies et al., 2014; Michanowicz et al., 2017).

The Tier 2 dataset represents a more conservative approach for public health and includes a broader set of criteria. This dataset includes all wells from Tier 1, and in addition it also includes any open well that is located within the same field area as the gas storage pool. While these wells are located outside of the storage pool, there is evidence from past gas storage events that wells within the same field area can provide a conduit for escaping gas. For instance, in 2001, in one of the most serious underground gas storage incidents to have occurred in the U.S., natural gas leaked from the Yaggy underground storage facility and migrated laterally underground over seven miles through geological units until it reached an abandoned well shaft in Hutchinson, Kansas, where the gas was able to migrate to the ground surface and cause a fatal explosion (Evans, 2009; Miyazaki, 2009; Yang et al., 2013). Pathways and failure modes are discussed further in Section 1.2 of this report. In addition, the set of Tier 2 wells serves as a proxy for where new storage wells might be located if future natural gas storage wells are drilled.

Population data

We obtained demographic information for the California general, youth, and elderly population from the United States Census Bureau. We downloaded age data from the 2010 Decennial Census at the block level (U.S. Census Bureau, 2011) to determine population counts for the following variables: total population, under five years of age, and 75 years and older. The under-five population was tallied by summing the male and female under five population counts. The 75 years of age and older population was tallied by summing the male and female counts for the age ranges 75 – 79, 80 – 84, and 85 years and over.

Sensitive receptors

We also collected data for a series of point locations we are calling “sensitive receptors,” which are places where vulnerable subgroups congregate: schools and daycare centers for the youth population; residential elderly care facilities for the elderly population; and hospitals for the sick. These locations represent sites where a hazard may pose elevated risk to people, because of their vulnerability.

We obtained data for California schools and their enrollment from the California Department of Education (CDE). This included aggregating data for public schools (CDE, 2017a), private schools, (CDE, 2017b), and nonpublic, nonsectarian schools (CDE, 2017c). In California, nonpublic nonsectarian schools are a type of private school that provide specialized services to students with disabilities (CDE, 2016). With the goal of limiting the dataset to locations where children ages 5 to 18 congregate regularly, we delete all closed facilities and any other locations that did not fit this definition, including district or agency headquarters, adult education centers, preschools, medical facility education options, and virtual schools. We deleted any schools listed in multiple datasets or with duplicate physical locations, in addition to any schools with a physical location outside of the state of California. The final dataset had 12,490 schools. All schools found in proximity to gas storage facilities in this analysis are currently open; none are pending.

Nonpublic nonsectarian schools and some private and public schools were missing enrollment data. We calculated the percentage of schools with enrollment data out of the total number of schools within each buffer distance for each facility, with a resulting range of 97.8–100% of the in-buffer schools with enrollment data. 86.4% of the storage facility buffer areas had 100% enrollment data for the schools within their boundaries. We obtained data for daycare centers from both the California Department of Social Services (CDSS) and the CDE. We defined daycares as sites that catered to care of groups of children less than five years of age, although we included sites that also included care for older children as long as the site was not also included in our schools dataset. From the California Department of Social Services (CDSS), we obtained datasets for child care centers and family child care homes CDSS, 2017a). These are distinguished by building type: child care centers are locations within commercial buildings, while family child care homes are located within parents' private homes (CDSS, 2017b). Within the schools datasets from the Department of Education, there were a number of sites that limited their enrollment to children of pre-school age. This was determined by a maximum grade level of Pre-K in the case of nonpublic nonsectarian schools (CDE, 2017c). With public school data, preschools were determined by the educational instruction level code, which listed grade levels taught and the school ownership code that described the type of school (CDE, 2017a). We deleted any duplicate daycares and/or preschools, as well as any facilities that were closed or had a status of inactive, leaving 26,799 remaining facilities. This dataset includes both currently open and pending daycare sites. Using the 5000 m buffer as a proxy to estimate the ratio of pending facilities, we estimate that 2.1% of daycare facilities have a pending status and are not currently open.

We downloaded residential elderly care locations from the CDSS (2017a). We deleted all closed sites. There were 8,056 remaining sites. Using the 5000 m buffer as a proxy to estimate the ratio of pending facilities, we estimate that 10.7% of residential elderly care locations have a pending status and are not currently open.

We obtained data for hospitals from the California Office of Statewide Health Planning and Development (OSHPD) from a dataset titled "Healthcare Facilities" (California OSHPD, 2017). To exclude other types of healthcare sites, we limited the dataset to only include facilities with a "Type" value of hospital. There were 629 facilities remaining. All of the hospitals in proximity to underground storage facilities are currently open.

Spatial analysis

Using ESRI ArcGIS 10.3 software, we created geodesic buffers at 0, 100, 200, 400, 600, 800, 1000, 1600, 2000, 5000, and 8000 meters around the storage facility boundaries. The 0 m buffer is the same thing as the storage facility boundary layer. The buffers used in this analysis are designed to encompass populations within various proximities to natural gas storage and associated emissions, with the assumption that exposure to emissions will be the highest at the 0 m buffer and will continue at decreasing exposures through the remaining buffers as distance from development increases. This assumption is supported by analysis of resident complaint calls summarized by the Los Angeles County Department of Public Health (LACDPH) in response to the Aliso Canyon incident, which found that the likelihood of reported health symptoms, including headache, nausea, nosebleeds, and respiratory problems, among other symptoms, was substantially greater for residents that lived ≤3 miles from the gas leak (55.8% of complaints) compared with residents that lived >5 miles from the gas leak (16.8% of complaints) (LACDPH, 2016). For risk in particular of well blowouts, there is evidence that, in the case of breach blowouts, the emission points to atmosphere (surface fractures or craters) typically do not exceed a distance of 600 m from the wellhead of the well that sustained the subsurface blowout (Jordan and Benson, 2009).

We added a final buffer utilizing results from the air dispersion data. This buffer represents the largest distance the 0.50 quantile level reaches outwards from the edge of each storage facility well boundary. Since the area around each UGS facility has different wind patterns, the maximum distance varies from site to site. To calculate this distance for each UGS, we calculated the minimum bounding geometry of each 0.50 quantile level polygon produced from the air dispersion modeling. We then measured the distance from the outermost wells to the minimum bounding geometry and determined which distance (from which outermost well) was the greatest at each facility. Over the facilities, these distances ranged from 7,977 m at Lodi Gas to 12,037 m at Montebello. We applied these distances to radial buffers, with each site having a unique buffer distance to produce the QL50 buffer layer. We only calculated the total number of people for this buffer; we did not calculate vulnerable population counts or sensitive receptors.

To calculate the number of total people, under five, and 75 years of age and older living within each buffer distance, we intersected the Census block polygons with each of the ten buffers, and then allocated block-level counts to areas within each buffer polygon by calculating the percentage of each census block residing with each aggregated buffer polygon, applying these percentages to population counts. This method is commonly known as areal estimation. We summed the calculated population counts over each buffer distance and over each oil and gas variable of interest.

There were 11,736 family child care homes from the daycare centers dataset that lacked either xy coordinates or street addresses, but did include spatial location data at the zip code level. To calculate the number of daycares for which we had zip-code level counts, we needed to take a different approach than was used to calculate the rest of the facility counts. For these sites, we performed linear regressions with daycare count as the dependent variable, and total population, under five, and age fourteen and younger, and land area in turn as the independent variables to determine which variable is the most strongly correlated with number of daycares within a zip code. Total population was the most strongly correlated with daycare count; therefore, we weighted daycare counts by population counts to estimate the number of daycares within each buffer.

For all sensitive receptor locations with xy coordinates, we imported them into ArcGIS using these coordinates. We geocoded all sites with street addresses using the World Geocode Service through ArcGIS Online. We then spatially joined schools, daycare facilities, elderly care facilities, and hospitals with each storage facility buffer which resulted in counts for each population aggregation site that are located within each buffer distance around each gas storage facility. We summed enrollment counts for all schools located within each storage facility buffer to calculate the total number of children enrolled in schools in proximity to each UGS facility.

To evaluate populations downwind of the gas storage facilities, we calculated spatial extents for the downwind areas that would capture air emissions from the gas facilities. These spatial extents were divided into six quantile levels (0.65, 0.75, 0.85, 0.95, 0.99, and 0.999) with each quantile level representing the percentage of the cumulative distribution that would fall *outside* of its spatial extent. For example, the 0.65 quantile level polygon shows the area for which 65% of the cumulative distribution would fall outside of, therefore 35% of the cumulative distribution would fall within. Like with the radial buffers, we intersected Census block polygons with each of the quantile level polygons and used areal estimation to estimate the total population residing within each quantile level for each storage facility.

Full results tables

Tables 1.4.C-1 through 1.4.C-3 provide population and sensitive receptor results for each individual facility and buffer distance or quantile level area.

Table 1.D-1. Tier 1 proximal population and sensitive receptor counts

ND indicates no data available. Gill Ranch Gas does not have values for the eastern and western portions of the facility split out for buffers larger than 800 meters, because at those distances the buffers overlapped, which would have caused double-accounting of population counts.

Facility Name	Buffer Distance	Total Population	Under 5	Age 75 & older	# School Total	# Open Schools	# Schools with Status Pending	# of Children Enrolled in School	# Elderly Care Facilities Total	# Open Elderly Care Facilities	# Elderly Care Facilities with Status Pending	# Hospitals	# Daycares Total (By zip code)	# Open Daycares (By zip code)	# Daycares with Status Pending (By zip code)
Aliso Canyon	0m	25	1	2	0	0	0	0	0	0	0	0	0	0	0
Aliso Canyon	100m	33	2	2	0	0	0	0	0	0	0	0	0	0	0
Aliso Canyon	200m	46	2	3	0	0	0	0	0	0	0	0	0	0	0
Aliso Canyon	400m	72	3	6	0	0	0	0	0	0	0	0	0	0	0
Aliso Canyon	600m	98	5	8	0	0	0	0	0	0	0	0	0	0	0
Aliso Canyon	800m	189	9	13	0	0	0	0	0	0	0	0	0	0	0
Aliso Canyon	1000m	916	42	43	0	0	0	0	0	0	0	0	0	0	0
Aliso Canyon	1600m	6,479	295	334	1	1	0	735	0	0	0	0	1	1	0
Aliso Canyon	2000m	9,305	420	471	2	2	0	1,857	0	0	0	0	2	2	0
Aliso Canyon	5000m	59,021	2,689	4,244	14	14	0	7,592	22	21	1	0	20	20	0
Aliso Canyon	8000m	232,202	12,502	14,692	77	77	0	48,000	104	93	11	2	75	74	1
Aliso Canyon	9116m (50% QL)	325,330	18,711	19,269	102	102	0	60,241	144	130	14	4	108	107	1
Gill Ranch Gas, East	0m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gill Ranch Gas, East	100m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gill Ranch Gas, East	200m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gill Ranch Gas, East	400m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gill Ranch Gas, East	600m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gill Ranch Gas, East	800m	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Gill Ranch Gas, East	1000m	ND	ND	ND	0	0	0	0	0	0	0	0	ND	0	0
Gill Ranch Gas, East	1600m	ND	ND	ND	0	0	0	0	0	0	0	0	ND	0	0
Gill Ranch Gas, East	2000m	ND	ND	ND	0	0	0	0	0	0	0	0	ND	0	0

Facility Name	Buffer Distance	Total Population	Under 5	Age 75 & older	# School Total	# Open Schools	# Schools with Status Pending	# of Children Enrolled in School	# Elderly Care Facilities Total	# Open Elderly Care Facilities	# Elderly Care Facilities with Status Pending	# Hospitals	# Daycares Total (By zip code)	# Open Daycares (By zip code)	# Daycares with Status Pending (By zip code)
Gill Ranch Gas, East	5000m	ND	ND	ND	0	0	0	0	0	0	0	0	ND	0	0
Gill Ranch Gas, West	0m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gill Ranch Gas, West	100m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gill Ranch Gas, West	200m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gill Ranch Gas, West	400m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gill Ranch Gas, West	600m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gill Ranch Gas, West	800m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gill Ranch Gas, West	1000m	ND	ND	ND	0	0	0	0	0	0	0	0	ND	0	0
Gill Ranch Gas, West	1600m	ND	ND	ND	0	0	0	0	0	0	0	0	ND	0	0
Gill Ranch Gas, West	2000m	ND	ND	ND	0	0	0	0	0	0	0	0	ND	0	0
Gill Ranch Gas, West	5000m	ND	ND	ND	0	0	0	0	0	0	0	0	ND	0	0
Gill Ranch Gas, Combined	0m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gill Ranch Gas, Combined	100m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gill Ranch Gas, Combined	200m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gill Ranch Gas, Combined	400m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gill Ranch Gas, Combined	600m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gill Ranch Gas, Combined	800m	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Gill Ranch Gas, Combined	1000m	2	0	0	0	0	0	0	0	0	0	0	0	0	0
Gill Ranch Gas, Combined	1600m	4	1	0	0	0	0	0	0	0	0	0	0	0	0

Facility Name	Buffer Distance	Total Population	Under 5	Age 75 & older	# School Total	# Open Schools	# Schools with Status Pending	# of Children Enrolled in School	# Elderly Care Facilities Total	# Open Elderly Care Facilities	# Elderly Care Facilities with Status Pending	# Hospitals	# Daycares Total (By zip code)	# Open Daycares (By zip code)	# Daycares with Status Pending (By zip code)
Gill Ranch Gas, Combined	2000m	6	1	0	0	0	0	0	0	0	0	0	0	0	0
Gill Ranch Gas, Combined	5000m	106	12	3	0	0	0	0	0	0	0	0	0	0	0
Gill Ranch Gas, Combined	8000m	545	55	18	0	0	0	0	0	0	0	0	0	0	0
Gill Ranch Gas, Combined	9124m (50% QL)	909	82	29	0	0	0	0	0	0	0	0	0	0	0
Honor Rancho	0m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Honor Rancho	100m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Honor Rancho	200m	0	0	0	2	2	0	1,028	0	0	0	0	0	0	0
Honor Rancho	400m	118	5	0	2	2	0	1,028	1	1	0	0	0	0	0
Honor Rancho	600m	439	25	3	2	2	0	1,028	1	1	0	0	0	0	0
Honor Rancho	800m	754	61	7	2	2	0	1,028	1	1	0	0	0	0	0
Honor Rancho	1000m	1,502	138	16	2	2	0	1,028	1	1	0	0	0	0	0
Honor Rancho	1600m	10,951	476	76	6	6	0	5,954	1	1	0	0	2	2	0
Honor Rancho	2000m	15,897	752	163	7	7	0	6,917	1	1	0	0	3	3	0
Honor Rancho	5000m	79,887	4,782	2,008	26	26	0	22,071	16	16	0	0	14	14	0
Honor Rancho	8000m	156,688	9,495	4,963	45	45	0	35,369	55	52	3	1	27	27	0
Honor Rancho	8998m (50% QL)	180,359	11,139	5,807	54	54	0	38,631	65	61	4	1	31	31	0
Kirby Hill Gas	0m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kirby Hill Gas	100m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kirby Hill Gas	200m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kirby Hill Gas	400m	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Kirby Hill Gas	600m	2	0	0	0	0	0	0	0	0	0	0	0	0	0
Kirby Hill Gas	800m	3	0	0	0	0	0	0	0	0	0	0	0	0	0

Facility Name	Buffer Distance	Total Population	Under 5	Age 75 & older	# School Total	# Open Schools	# Schools with Status Pending	# of Children Enrolled in School	# Elderly Care Facilities Total	# Open Elderly Care Facilities	# Elderly Care Facilities with Status Pending	# Hospitals	# Daycares Total (By zip code)	# Open Daycares (By zip code)	# Daycares with Status Pending (By zip code)
Kirby Hill Gas	1000m	5	0	0	0	0	0	0	0	0	0	0	0	0	0
Kirby Hill Gas	1600m	11	0	1	0	0	0	0	0	0	0	0	0	0	0
Kirby Hill Gas	2000m	15	0	1	0	0	0	0	0	0	0	0	0	0	0
Kirby Hill Gas	5000m	89	6	6	0	0	0	0	0	0	0	0	0	0	0
Kirby Hill Gas	8000m	291	11	14	0	0	0	0	0	0	0	0	0	0	0
Kirby Hill Gas	9813m (50% QL)	401	17	18	0	0	0	0	0	0	0	0	0	0	0
La Goleta Gas	0m	39	1	3	0	0	0	0	0	0	0	0	0	0	0
La Goleta Gas	100m	67	1	5	0	0	0	0	0	0	0	0	0	0	0
La Goleta Gas	200m	111	2	7	0	0	0	0	0	0	0	0	0	0	0
La Goleta Gas	400m	280	3	17	0	0	0	0	0	0	0	0	0	0	0
La Goleta Gas	600m	791	16	50	0	0	0	0	0	0	0	0	0	0	0
La Goleta Gas	800m	2,105	26	64	0	0	0	0	0	0	0	0	0	0	0
La Goleta Gas	1000m	2,855	27	70	0	0	0	0	0	0	0	0	1	1	0
La Goleta Gas	1600m	7,875	71	119	0	0	0	0	0	0	0	0	1	1	0
La Goleta Gas	2000m	17,794	377	314	2	2	0	229	0	0	0	1	3	3	0
La Goleta Gas	5000m	67,731	2,515	3,841	15	15	0	8,242	33	33	0	2	15	14	1
La Goleta Gas	8000m	94,421	3,734	6,719	26	26	0	12,132	40	39	1	3	21	20	1
La Goleta Gas	8608m (50% QL)	101,371	4,040	7,611	32	32	0	13,991	42	41	1	3	22	21	1
Lodi Gas	0m	242	12	9	0	0	0	0	0	0	0	0	0	0	0
Lodi Gas	100m	310	16	12	0	0	0	0	0	0	0	0	0	0	0
Lodi Gas	200m	376	19	14	0	0	0	0	0	0	0	0	0	0	0
Lodi Gas	400m	512	27	20	1	1	0	402	0	0	0	0	0	0	0
Lodi Gas	600m	658	34	26	1	1	0	402	0	0	0	0	0	0	0
Lodi Gas	800m	809	41	32	1	1	0	402	0	0	0	0	0	0	0
Lodi Gas	1000m	963	49	40	1	1	0	402	0	0	0	0	0	0	0
Lodi Gas	1600m	1,521	81	69	1	1	0	402	0	0	0	0	0	0	0

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Lodi Gas	2000m	1,836	98	92	1	1	0	402	0	0	0	0	0	0	0
Lodi Gas	5000m	7,303	404	419	1	1	0	402	0	0	0	0	1	1	0
Lodi Gas	7977m (50% QL)	23,771	1,600	1,576	9	9	0	2,851	2	2	0	0	4	4	0
Lodi Gas	8000m	24,114	1,625	1,595	9	9	0	2,851	2	2	0	0	4	4	0
Los Medanos Gas	0m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Los Medanos Gas	100m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Los Medanos Gas	200m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Los Medanos Gas	400m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Los Medanos Gas	600m	3	0	0	0	0	0	0	0	0	0	0	0	0	0
Los Medanos Gas	800m	5	0	0	1	1	0	211	0	0	0	0	0	0	0
Los Medanos Gas	1000m	8	0	0	1	1	0	211	0	0	0	0	0	0	0
Los Medanos Gas	1600m	740	51	21	1	1	0	211	0	0	0	0	0	0	0
Los Medanos Gas	2000m	1,533	105	34	1	1	0	211	0	0	0	0	0	0	0
Los Medanos Gas	5000m	46,312	3,479	1,929	15	15	0	5,311	19	16	3	1	11	11	0
Los Medanos Gas	8000m	139,902	9,981	6,457	43	43	0	15,551	66	60	6	2	40	39	0
Los Medanos Gas	9743m (50% QL)	223,069	15,640	10,407	63	63	0	29,169	99	92	7	3	70	69	1
McDonald Island Gas	0m	24	4	0	0	0	0	0	0	0	0	0	0	0	0
McDonald Island Gas	100m	29	4	0	0	0	0	0	0	0	0	0	0	0	0
McDonald Island Gas	200m	34	5	0	0	0	0	0	0	0	0	0	0	0	0
McDonald Island Gas	400m	44	6	0	0	0	0	0	0	0	0	0	0	0	0
McDonald Island Gas	600m	55	7	0	0	0	0	0	0	0	0	0	0	0	0

Facility Name	Buffer Distance	Total Population	Under 5	Age 75 & older	# School Total	# Open Schools	# Schools with Status Pending	# of Children Enrolled in School	# Elderly Care Facilities Total	# Open Elderly Care Facilities	# Elderly Care Facilities with Status Pending	# Hospitals	# Daycares Total (By zip code)	# Open Daycares (By zip code)	# Daycares with Status Pending (By zip code)
McDonald Island Gas	800m	66	9	1	0	0	0	0	0	0	0	0	0	0	0
McDonald Island Gas	1000m	75	10	1	0	0	0	0	0	0	0	0	0	0	0
McDonald Island Gas	1600m	106	13	1	0	0	0	0	0	0	0	0	0	0	0
McDonald Island Gas	2000m	124	14	2	0	0	0	0	0	0	0	0	0	0	0
McDonald Island Gas	5000m	315	28	9	0	0	0	0	0	0	0	0	0	0	0
McDonald Island Gas	8000m	646	51	17	0	0	0	0	0	0	0	0	0	0	0
McDonald Island Gas	9282m (50% QL)	6,473	388	244	0	0	0	0	0	0	0	0	2	2	0
Montebello	0m	1,470	75	149	0	0	0	0	0	0	0	0	0	0	0
Montebello	100m	2,875	175	250	0	0	0	0	0	0	0	0	1	1	0
Montebello	200m	4,338	267	400	0	0	0	0	1	1	0	0	1	1	0
Montebello	400m	7,563	427	849	0	0	0	0	1	1	0	0	2	2	0
Montebello	600m	10,820	612	1,153	3	3	0	1,620	1	1	0	0	3	3	0
Montebello	800m	15,053	830	1,496	4	4	0	2,108	1	1	0	0	5	5	0
Montebello	1000m	20,661	1,194	1,931	6	6	0	5,700	1	1	0	1	6	6	0
Montebello	1600m	41,170	2,611	3,246	14	14	0	12,129	2	1	1	1	13	13	0
Montebello	2000m	58,953	3,889	4,423	17	17	0	14,185	2	1	1	1	18	18	0
Montebello	5000m	274,813	18,079	19,039	77	77	0	47,471	5	3	2	4	75	74	1
Montebello	8000m	734,877	51,768	42,119	198	198	0	117,402	20	17	3	10	201	200	1
Montebello	12037m (50% QL)	1,594,128	113,206	81,789	483	482	1	273,453	70	59	11	26	389	387	2
Playa del Rey	0m	3,782	165	193	0	0	0	0	0	0	0	0	0	0	0

Facility Name	Buffer Distance	Total Population	Under 5	Age 75 & older	# School Total	# Open Schools	# Schools with Status Pending	# of Children Enrolled in School	# Elderly Care Facilities Total	# Open Elderly Care Facilities	# Elderly Care Facilities with Status Pending	# Hospitals	# Daycares Total (By zip code)	# Open Daycares (By zip code)	# Daycares with Status Pending (By zip code)
Playa del Rey	100m	4,858	210	272	0	0	0	0	0	0	0	0	0	0	0
Playa del Rey	200m	6,529	273	364	1	1	0	18	0	0	0	0	0	0	0
Playa del Rey	400m	9,780	405	542	1	1	0	18	0	0	0	0	0	0	0
Playa del Rey	600m	15,275	610	817	3	3	0	649	0	0	0	0	1	1	0
Playa del Rey	800m	21,495	867	1,090	4	4	0	1,686	0	0	0	0	1	1	0
Playa del Rey	1000m	27,113	1,136	1,355	7	7	0	2,633	0	0	0	0	1	1	0
Playa del Rey	1600m	44,816	1,924	2,407	9	9	0	3,604	1	1	0	1	4	4	0
Playa del Rey	2000m	55,833	2,392	2,961	12	12	0	5,067	1	1	0	1	6	6	0
Playa del Rey	5000m	200,561	10,091	11,517	59	59	0	24,611	27	20	7	1	63	62	1
Playa del Rey	8000m	493,459	26,787	27,065	158	158	0	65,306	81	69	12	5	171	169	2
Playa del Rey	9506m (50% QL)	691,757	39,352	38,121	218	218	0	93,325	97	85	12	9	263	259	3
Pleasant Creek	0m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pleasant Creek	100m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pleasant Creek	200m	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Pleasant Creek	400m	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Pleasant Creek	600m	3	0	0	0	0	0	0	0	0	0	0	0	0	0
Pleasant Creek	800m	5	0	0	0	0	0	0	0	0	0	0	0	0	0
Pleasant Creek	1000m	8	0	0	0	0	0	0	0	0	0	0	0	0	0
Pleasant Creek	1600m	16	1	1	0	0	0	0	0	0	0	0	0	0	0
Pleasant Creek	2000m	25	1	1	0	0	0	0	0	0	0	0	0	0	0
Pleasant Creek	5000m	7,082	442	280	4	4	0	0	0	0	0	0	2	2	0
Pleasant Creek	8000m	8,270	522	342	4	4	0	0	0	0	0	0	2	2	0
Pleasant Creek	9553m (50% QL)	8,821	545	373	4	4	0	0	0	0	0	0	2	2	0
Princeton Gas	0m	3	0	0	0	0	0	0	0	0	0	0	0	0	0

Facility Name	Buffer Distance	Total Population	Under 5	Age 75 & older	# School Total	# Open Schools	# Schools with Status Pending	# of Children Enrolled in School	# Elderly Care Facilities Total	# Open Elderly Care Facilities	# Elderly Care Facilities with Status Pending	# Hospitals	# Daycares Total (By zip code)	# Open Daycares (By zip code)	# Daycares with Status Pending (By zip code)
Princeton Gas	100m	5	0	0	0	0	0	0	0	0	0	0	0	0	0
Princeton Gas	200m	8	0	0	0	0	0	0	0	0	0	0	0	0	0
Princeton Gas	400m	13	0	1	0	0	0	0	0	0	0	0	0	0	0
Princeton Gas	600m	15	0	1	0	0	0	0	0	0	0	0	0	0	0
Princeton Gas	800m	16	0	1	0	0	0	0	0	0	0	0	0	0	0
Princeton Gas	1000m	18	0	1	0	0	0	0	0	0	0	0	0	0	0
Princeton Gas	1600m	29	0	3	0	0	0	0	0	0	0	0	0	0	0
Princeton Gas	2000m	43	1	4	0	0	0	0	0	0	0	0	0	0	0
Princeton Gas	5000m	425	14	26	2	2	0	169	0	0	0	0	0	0	0
Princeton Gas	8000m	642	30	47	2	2	0	169	0	0	0	0	0	0	0
Princeton Gas	9686m (50% QL)	848	41	59	2	2	0	169	0	0	0	0	0	0	0
Wild Goose Gas	0m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wild Goose Gas	100m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wild Goose Gas	200m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wild Goose Gas	400m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wild Goose Gas	600m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wild Goose Gas	800m	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Wild Goose Gas	1000m	2	0	0	0	0	0	0	0	0	0	0	0	0	0
Wild Goose Gas	1600m	3	0	0	0	0	0	0	0	0	0	0	0	0	0
Wild Goose Gas	2000m	3	0	0	0	0	0	0	0	0	0	0	0	0	0
Wild Goose Gas	5000m	32	1	2	0	0	0	0	0	0	0	0	0	0	0
Wild Goose Gas	8000m	116	4	6	0	0	0	0	0	0	0	0	0	0	0
Wild Goose Gas	9102m (50% QL)	195	9	11	0	0	0	0	0	0	0	0	0	0	0

Table 1.D-2. Tier 2 proximal population and sensitive receptor counts.

Facility Name	Buffer Distance	Total Population	Under 5	Age 75 & older	# School Total	# Open Schools	# Schools with Status Pending	# of Children Enrolled in School	# Elderly Care Facilities Total	# Open Elderly Care Facilities	# Elderly Care Facilities with Status Pending	# Hospitals	# Daycares Total (By zip code)	# Open Daycares (By zip code)	# Daycares with Status Pending (By zip code)
Aliso Canyon	0m	25	1	2	0	0	0	0	0	0	0	0	0	0	0
Aliso Canyon	100m	34	2	2	0	0	0	0	0	0	0	0	0	0	0
Aliso Canyon	200m	46	2	3	0	0	0	0	0	0	0	0	0	0	0
Aliso Canyon	400m	72	3	6	0	0	0	0	0	0	0	0	0	0	0
Aliso Canyon	600m	98	5	8	0	0	0	0	0	0	0	0	0	0	0
Aliso Canyon	800m	190	9	13	0	0	0	0	0	0	0	0	0	0	0
Aliso Canyon	1000m	917	42	43	0	0	0	0	0	0	0	0	0	0	0
Aliso Canyon	1600m	6,479	295	334	1	1	0	735	0	0	0	0	1	1	0
Aliso Canyon	2000m	9,305	420	471	2	2	0	1,857	0	0	0	0	2	2	0
Aliso Canyon	5000m	59,142	2,696	4,248	14	14	0	7,592	22	21	1	0	20	20	0
Aliso Canyon	8000m	236,235	12,760	14,823	79	79	0	49,267	107	96	11	2	75	74	1
Aliso Canyon	9116m (50% QL)	327,500	18,817	19,371	103	103	0	61,206	145	131	14	4	108	107	1
Gill Ranch Gas	0m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gill Ranch Gas	100m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gill Ranch Gas	200m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gill Ranch Gas	400m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gill Ranch Gas	600m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gill Ranch Gas	800m	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Gill Ranch Gas	1000m	2	0	0	0	0	0	0	0	0	0	0	0	0	0
Gill Ranch Gas	1600m	4	1	0	0	0	0	0	0	0	0	0	0	0	0
Gill Ranch Gas	2000m	6	1	0	0	0	0	0	0	0	0	0	0	0	0
Gill Ranch Gas	5000m	114	13	3	0	0	0	0	0	0	0	0	0	0	0
Gill Ranch Gas	8000m	556	56	18	0	0	0	0	0	0	0	0	0	0	0

Facility Name	Buffer Distance	Total Population	Under 5	Age 75 & older	# School Total	# Open Schools	# Schools with Status Pending	# of Children Enrolled in School	# Elderly Care Facilities Total	# Open Elderly Care Facilities	# Elderly Care Facilities with Status Pending	# Hospitals	# Daycares Total (By zip code)	# Open Daycares (By zip code)	# Daycares with Status Pending (By zip code)
Gill Ranch Gas	9124m (50% QL)	930	85	29	0	0	0	0	0	0	0	0	0	0	0
Honor Rancho	0m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Honor Rancho	100m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Honor Rancho	200m	0	0	0	2	2	0	1,028	0	0	0	0	0	0	0
Honor Rancho	400m	118	5	0	2	2	0	1,028	1	1	0	0	0	0	0
Honor Rancho	600m	439	25	3	2	2	0	1,028	1	1	0	0	0	0	0
Honor Rancho	800m	754	61	7	2	2	0	1,028	1	1	0	0	0	0	0
Honor Rancho	1000m	1,502	138	16	2	2	0	1,028	1	1	0	0	0	0	0
Honor Rancho	1600m	10,951	476	76	6	6	0	5,954	1	1	0	0	2	2	0
Honor Rancho	2000m	15,900	752	163	7	7	0	6,917	1	1	0	0	3	3	0
Honor Rancho	5000m	79,937	4,785	2,010	26	26	0	22,071	16	16	0	0	14	14	0
Honor Rancho	8000m	156,868	9,506	4,968	45	45	0	35,369	55	52	3	1	27	27	0
Honor Rancho	8998m (50% QL)	180,429	11,144	5,810	54	54	0	38,631	65	61	4	1	31	31	0
Kirby Hill Gas	0m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kirby Hill Gas	100m	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Kirby Hill Gas	200m	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Kirby Hill Gas	400m	2	0	0	0	0	0	0	0	0	0	0	0	0	0
Kirby Hill Gas	600m	4	0	0	0	0	0	0	0	0	0	0	0	0	0
Kirby Hill Gas	800m	6	0	0	0	0	0	0	0	0	0	0	0	0	0
Kirby Hill Gas	1000m	8	0	1	0	0	0	0	0	0	0	0	0	0	0
Kirby Hill Gas	1600m	16	0	1	0	0	0	0	0	0	0	0	0	0	0
Kirby Hill Gas	2000m	22	0	2	0	0	0	0	0	0	0	0	0	0	0
Kirby Hill Gas	5000m	101	7	7	0	0	0	0	0	0	0	0	0	0	0
Kirby Hill Gas	8000m	758	44	23	0	0	0	0	0	0	0	0	0	0	0

Facility Name	Buffer Distance	Total Population	Under 5	Age 75 & older	# School Total	# Open Schools	# Schools with Status Pending	# of Children Enrolled in School	# Elderly Care Facilities Total	# Open Elderly Care Facilities	# Elderly Care Facilities with Status Pending	# Hospitals	# Daycares Total (By zip code)	# Open Daycares (By zip code)	# Daycares with Status Pending (By zip code)
Kirby Hill Gas	9813m (50% QL)	13,608	944	433	2	2	0	0	0	8	0	0	7	7	0
La Goleta Gas	0m	39	1	3	0	0	0	0	0	0	0	0	0	0	0
La Goleta Gas	100m	67	1	5	0	0	0	0	0	0	0	0	0	0	0
La Goleta Gas	200m	111	2	7	0	0	0	0	0	0	0	0	0	0	0
La Goleta Gas	400m	280	3	17	0	0	0	0	0	0	0	0	0	0	0
La Goleta Gas	600m	791	16	50	0	0	0	0	0	0	0	0	0	0	0
La Goleta Gas	800m	2,105	26	64	0	0	0	0	0	0	0	0	0	0	0
La Goleta Gas	1000m	2,855	27	70	0	0	0	0	0	0	0	0	1	1	0
La Goleta Gas	1600m	7,875	71	119	0	0	0	0	0	0	0	0	1	1	0
La Goleta Gas	2000m	17,794	377	314	2	2	0	229	0	0	0	1	3	3	0
La Goleta Gas	5000m	67,731	2,515	3,841	15	15	0	8,242	33	33	0	2	15	14	1
La Goleta Gas	8000m	94,421	3,734	6,719	26	26	0	12,132	40	39	1	3	21	20	1
La Goleta Gas	8608m (50% QL)	101,369	4,041	7,611	32	32	0	13,991	42	41	1	3	22	21	1
Lodi Gas	0m	242	12	9	0	0	0	0	0	0	0	0	0	0	0
Lodi Gas	100m	310	16	12	0	0	0	0	0	0	0	0	0	0	0
Lodi Gas	200m	376	19	14	0	0	0	0	0	0	0	0	0	0	0
Lodi Gas	400m	512	27	20	1	1	0	402	0	0	0	0	0	0	0
Lodi Gas	600m	658	34	26	1	1	0	402	0	0	0	0	0	0	0
Lodi Gas	800m	809	41	32	1	1	0	402	0	0	0	0	0	0	0
Lodi Gas	1000m	963	49	40	1	1	0	402	0	0	0	0	0	0	0
Lodi Gas	1600m	1,521	81	69	1	1	0	402	0	0	0	0	0	0	0
Lodi Gas	2000m	1,836	98	92	1	1	0	402	0	0	0	0	0	0	0
Lodi Gas	5000m	7,303	404	419	1	1	0	402	0	0	0	0	1	1	0
Lodi Gas	8000m	24,114	1,625	1,595	9	9	0	2,851	2	2	0	0	4	4	0

Facility Name	Buffer Distance	Total Population	Under 5	Age 75 & older	# School Total	# Open Schools	# Schools with Status Pending	# of Children Enrolled in School	# Elderly Care Facilities Total	# Open Elderly Care Facilities	# Elderly Care Facilities with Status Pending	# Hospitals	# Daycares Total (By zip code)	# Open Daycares (By zip code)	# Daycares with Status Pending (By zip code)
Lodi Gas	7977m (50% QL)	23,759	1,601	1,575	9	9	0	2,851	2	2	0	0	4	4	0
Los Medanos Gas	0m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Los Medanos Gas	100m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Los Medanos Gas	200m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Los Medanos Gas	400m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Los Medanos Gas	600m	3	0	0	0	0	0	0	0	0	0	0	0	0	0
Los Medanos Gas	800m	118	6	7	1	1	0	211	0	0	0	0	0	0	0
Los Medanos Gas	1000m	742	45	23	1	1	0	211	0	0	0	0	0	0	0
Los Medanos Gas	1600m	933	58	25	1	1	0	211	0	0	0	0	0	0	0
Los Medanos Gas	2000m	1,537	106	34	1	1	0	211	0	0	0	0	0	0	0
Los Medanos Gas	5000m	47,273	3,545	1,965	15	15	0	5,311	19	16	3	2	11	11	0
Los Medanos Gas	8000m	147,142	10,421	6,752	45	45	0	16,945	66	63	6	2	42	41	0
Los Medanos Gas	9743m (50% QL)	231,030	16,005	10,921	64	64	0	29,580	103	94	9	3	72	72	1
McDonald Island Gas	0m	24	4	0	0	0	0	0	0	0	0	0	0	0	0
McDonald Island Gas	100m	29	4	0	0	0	0	0	0	0	0	0	0	0	0
McDonald Island Gas	200m	34	5	0	0	0	0	0	0	0	0	0	0	0	0
McDonald Island Gas	400m	44	6	0	0	0	0	0	0	0	0	0	0	0	0
McDonald Island Gas	600m	55	7	0	0	0	0	0	0	0	0	0	0	0	0
McDonald Island Gas	800m	66	9	1	0	0	0	0	0	0	0	0	0	0	0
McDonald Island Gas	1000m	75	10	1	0	0	0	0	0	0	0	0	0	0	0

Facility Name	Buffer Distance	Total Population	Under 5	Age 75 & older	# School Total	# Open Schools	# Schools with Status Pending	# of Children Enrolled in School	# Elderly Care Facilities Total	# Open Elderly Care Facilities	# Elderly Care Facilities with Status Pending	# Hospitals	# Daycares Total (By zip code)	# Open Daycares (By zip code)	# Daycares with Status Pending (By zip code)
McDonald Island Gas	1600m	106	13	1	0	0	0	0	0	0	0	0	0	0	0
McDonald Island Gas	2000m	124	14	2	0	0	0	0	0	0	0	0	0	0	0
McDonald Island Gas	5000m	315	28	9	0	0	0	0	0	0	0	0	0	0	0
McDonald Island Gas	8000m	646	51	17	0	0	0	0	0	0	0	0	0	0	0
McDonald Island Gas	9282m (50% QL)	6,373	383	238	0	0	0	0	0	0	0	0	2	2	0
Montebello	0m	3,380	210	258	0	0	0	0	0	0	0	0	1	1	0
Montebello	100m	4,719	275	389	0	0	0	0	0	0	0	0	1	1	0
Montebello	200m	6,247	344	588	0	0	0	0	1	1	0	0	2	2	0
Montebello	400m	10,221	533	1,152	2	2	0	2,048	1	1	0	0	3	3	0
Montebello	600m	14,656	802	1,553	5	5	0	3,668	1	1	0	1	4	4	0
Montebello	800m	19,174	1,026	1,926	6	6	0	4,156	1	1	0	1	6	6	0
Montebello	1000m	25,363	1,432	2,384	8	8	0	7,748	1	1	0	1	8	8	0
Montebello	1600m	46,399	2,940	3,677	15	15	0	12,324	2	1	1	1	14	14	0
Montebello	2000m	66,373	4,356	4,960	19	19	0	14,756	2	1	1	1	20	20	0
Montebello	5000m	284,810	18,779	19,589	79	79	0	48,237	5	3	2	4	79	78	1
Montebello	8000m	763,179	54,008	43,450	210	210	0	120,267	21	18	3	10	207	206	1
Montebello	12037m (50% QL)	1,636,136	115,897	84,019	500	499	1	282,719	73	62	11	26	397	395	2
Playa del Rey	0m	3,782	165	193	0	0	0	0	0	0	0	0	0	0	0
Playa del Rey	100m	4,858	210	272	0	0	0	0	0	0	0	0	0	0	0
Playa del Rey	200m	6,529	273	364	1	1	0	18	0	0	0	0	0	0	0
Playa del Rey	400m	9,780	405	542	1	1	0	18	0	0	0	0	0	0	0
Playa del Rey	600m	15,275	610	817	3	3	0	649	0	0	0	0	1	1	0

Facility Name	Buffer Distance	Total Population	Under 5	Age 75 & older	# School Total	# Open Schools	# Schools with Status Pending	# of Children Enrolled in School	# Elderly Care Facilities Total	# Open Elderly Care Facilities	# Elderly Care Facilities with Status Pending	# Hospitals	# Daycares Total (By zip code)	# Open Daycares (By zip code)	# Daycares with Status Pending (By zip code)
Playa del Rey	800m	21,495	867	1,090	4	4	0	1,686	0	0	0	0	1	1	0
Playa del Rey	1000m	27,113	1,136	1,355	7	7	0	2,633	0	0	0	0	1	1	0
Playa del Rey	1600m	44,816	1,924	2,407	9	9	0	3,604	1	1	0	1	4	4	0
Playa del Rey	2000m	55,833	2,392	2,961	12	12	0	5,067	1	1	0	1	6	6	0
Playa del Rey	5000m	200,561	10,091	11,517	59	59	0	24,611	27	20	7	1	63	62	1
Playa del Rey	8000m	493,459	26,787	27,065	158	158	0	65,306	81	69	12	5	171	169	2
Playa del Rey	9506m (50% QL)	692,222	39,386	38,144	218	218	0	93,325	97	85	12	9	263	260	3
Pleasant Creek	0m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pleasant Creek	100m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pleasant Creek	200m	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Pleasant Creek	400m	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Pleasant Creek	600m	3	0	0	0	0	0	0	0	0	0	0	0	0	0
Pleasant Creek	800m	5	0	0	0	0	0	0	0	0	0	0	0	0	0
Pleasant Creek	1000m	8	0	0	0	0	0	0	0	0	0	0	0	0	0
Pleasant Creek	1600m	16	1	1	0	0	0	0	0	0	0	0	0	0	0
Pleasant Creek	2000m	25	1	1	0	0	0	0	0	0	0	0	0	0	0
Pleasant Creek	5000m	7,082	442	280	4	4	0	0	0	0	0	0	2	2	0
Pleasant Creek	8000m	8,270	522	342	4	4	0	0	0	0	0	0	2	2	0
Pleasant Creek	9553m (50% QL)	8,823	546	374	4	4	0	0	0	0	0	0	2	2	0
Princeton Gas	0m	3	0	0	0	0	0	0	0	0	0	0	0	0	0
Princeton Gas	100m	5	0	0	0	0	0	0	0	0	0	0	0	0	0
Princeton Gas	200m	8	0	0	0	0	0	0	0	0	0	0	0	0	0
Princeton Gas	400m	13	0	1	0	0	0	0	0	0	0	0	0	0	0
Princeton Gas	600m	15	0	1	0	0	0	0	0	0	0	0	0	0	0
Princeton Gas	800m	16	0	1	0	0	0	0	0	0	0	0	0	0	0

Facility Name	Buffer Distance	Total Population	Under 5	Age 75 & older	# School Total	# Open Schools	# Schools with Status Pending	# of Children Enrolled in School	# Elderly Care Facilities Total	# Open Elderly Care Facilities	# Elderly Care Facilities with Status Pending	# Hospitals	# Daycares Total (By zip code)	# Open Daycares (By zip code)	# Daycares with Status Pending (By zip code)
Princeton Gas	1000m	18	0	1	0	0	0	0	0	0	0	0	0	0	0
Princeton Gas	1600m	29	0	3	0	0	0	0	0	0	0	0	0	0	0
Princeton Gas	2000m	43	1	4	0	0	0	0	0	0	0	0	0	0	0
Princeton Gas	5000m	425	14	26	2	2	0	169	0	0	0	0	0	0	0
Princeton Gas	8000m	642	30	47	2	2	0	169	0	0	0	0	0	0	0
Princeton Gas	9686m (50% QL)	849	41	59	2	2	0	169	0	0	0	0	0	0	0
Wild Goose Gas	0m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wild Goose Gas	100m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wild Goose Gas	200m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wild Goose Gas	400m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wild Goose Gas	600m	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wild Goose Gas	800m	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Wild Goose Gas	1000m	2	0	0	0	0	0	0	0	0	0	0	0	0	0
Wild Goose Gas	1600m	3	0	0	0	0	0	0	0	0	0	0	0	0	0
Wild Goose Gas	2000m	3	0	0	0	0	0	0	0	0	0	0	0	0	0
Wild Goose Gas	5000m	32	1	2	0	0	0	0	0	0	0	0	0	0	0
Wild Goose Gas	8000m	116	4	6	0	0	0	0	0	0	0	0	0	0	0
Wild Goose Gas	9102m (50% QL)	196	10	11	0	0	0	0	0	0	0	0	0	0	0

Table 1.D-3. Air dispersion contour quantile level area proximal population counts.

Facility Name	Quantile Level	Contour Level (ug/m3) / (ug/s)	Total population	Area_sqkm	Population density (people/sqkm)
Aliso Canyon	0.999	0.000003406	0	0.4	0.9
Aliso Canyon	0.99	0.000000913	38	4.1	9.3
Aliso Canyon	0.95	0.000000108	6,910	20.1	343.5
Aliso Canyon	0.85	0.000000033	37,027	60.3	613.6
Aliso Canyon	0.75	0.00000002	88,854	100.4	885.0
Aliso Canyon	0.65	0.000000014	144,290	140.7	1,025.8
Aliso Canyon	0.5	0.000000008	219,991	201.0	1,094.6
Aliso Canyon	0.3	0.000000004	291,814	280.9	1,038.8
Gill Ranch Gas	0.999	0.000005412	0	0.4	0.0
Gill Ranch Gas	0.99	0.000000827	0	4.1	0.0
Gill Ranch Gas	0.95	0.000000128	4	19.6	0.2
Gill Ranch Gas	0.85	0.00000004	60	58.9	1.0
Gill Ranch Gas	0.75	0.000000023	168	98.2	1.7
Gill Ranch Gas	0.65	0.000000015	279	137.6	2.0
Gill Ranch Gas	0.5	0.000000009	492	196.5	2.5
Gill Ranch Gas	0.3	0.000000005	730	274.7	2.7
Honor Rancho	0.999	0.000006752	0	0.4	0.2
Honor Rancho	0.99	0.000001172	256	4.0	64.8
Honor Rancho	0.95	0.000000155	8,248	19.7	419.0
Honor Rancho	0.85	0.000000049	23,776	58.9	403.3
Honor Rancho	0.75	0.00000003	41,099	98.2	418.6
Honor Rancho	0.65	0.000000022	61,410	137.6	446.1
Honor Rancho	0.5	0.000000015	90,520	196.5	460.7
Honor Rancho	0.3	0.000000007	144,537	275.1	525.3
Kirby Hill Gas	0.999	0.000007042	0	0.4	0.7
Kirby Hill Gas	0.99	0.000000718	4	3.7	1.2
Kirby Hill Gas	0.95	0.000000115	21	18.2	1.2
Kirby Hill Gas	0.85	0.00000004	129	54.4	2.4
Kirby Hill Gas	0.75	0.000000022	180	90.7	2.0
Kirby Hill Gas	0.65	0.000000014	218	126.9	1.7
Kirby Hill Gas	0.5	0.000000009	272	181.5	1.5
Kirby Hill Gas	0.3	0.000000005	334	253.8	1.3
La Goleta Gas	0.999	0.000009701	26	0.3	76.2
La Goleta Gas	0.99	0.000000782	695	3.5	196.6
La Goleta Gas	0.95	0.000000137	14,542	17.9	810.3
La Goleta Gas	0.85	0.000000047	57,823	53.6	1,079.6
La Goleta Gas	0.75	0.000000029	75,858	89.3	849.4
La Goleta Gas	0.65	0.000000021	89,830	125.1	718.3
La Goleta Gas	0.5	0.000000015	99,546	178.6	557.2

Facility Name	**Quantile Level**	**Contour Level (ug/m3) / (ug/s)**	**Total population**	**Area_sqkm**	**Population density (people/sqkm)**
La Goleta Gas	0.3	0.000000008	108,316	250.1	433.0
Facility Name	Quantile Level	Contour Level (ug/m3) / (ug/s)	Total population	Area_sqkm	Population density (people/sqkm)
Lodi Gas	0.999	0.000009251	18	0.4	48.5
Lodi Gas	0.99	0.000000897	218	3.7	59.0
Lodi Gas	0.95	0.000000152	1,056	18.3	57.6
Lodi Gas	0.85	0.00000005	3,243	54.9	59.0
Lodi Gas	0.75	0.00000003	5,520	91.4	60.4
Lodi Gas	0.65	0.000000022	7,010	128.1	54.7
Lodi Gas	0.5	0.000000015	13,634	182.6	74.7
Lodi Gas	0.3	0.000000008	23,438	256.0	91.6
Los Medanos Gas	0.999	0.000005573	0	0.4	0.0
Los Medanos Gas	0.99	0.000000508	10	3.8	2.8
Los Medanos Gas	0.95	0.000000088	2,326	18.8	123.4
Los Medanos Gas	0.85	0.00000003	14,237	56.5	252.0
Los Medanos Gas	0.75	0.000000018	24,188	94.1	257.1
Los Medanos Gas	0.65	0.000000011	44,382	131.6	337.3
Los Medanos Gas	0.5	0.000000006	90,444	188.3	480.3
Los Medanos Gas	0.3	0.000000003	174,768	263.4	663.6
McDonald Island Gas	0.999	0.000007966	3	0.4	7.1
McDonald Island Gas	0.99	0.000000828	25	4.0	6.2
McDonald Island Gas	0.95	0.000000127	95	19.6	4.8
McDonald Island Gas	0.85	0.000000042	222	58.7	3.8
McDonald Island Gas	0.75	0.000000026	309	97.7	3.2
McDonald Island Gas	0.65	0.000000018	3,767	136.9	27.5
McDonald Island Gas	0.5	0.000000011	6,223	195.4	31.9
McDonald Island Gas	0.3	0.000000006	8,115	273.8	29.6
Montebello	0.999	0.000006407	133	0.4	366.5
Montebello	0.99	0.00000124	3,038	4.0	758.6
Montebello	0.95	0.000000173	30,779	20.0	1,538.4
Montebello	0.85	0.000000053	178,963	60.0	2,982.0
Montebello	0.75	0.000000031	313,758	99.9	3,140.6
Montebello	0.65	0.00000002	422,241	139.9	3,018.0
Montebello	0.5	0.000000012	607,185	199.6	3,041.9
Montebello	0.3	0.000000006	864,751	279.6	3,093.3
Playa del Rey	0.999	0.000010763	263	0.4	714.4
Playa del Rey	0.99	0.000000962	6,613	3.7	1,775.4
Playa del Rey	0.95	0.00000017	36,590	18.6	1,966.5
Playa del Rey	0.85	0.000000057	106,209	55.6	1,910.2
Playa del Rey	0.75	0.000000035	161,038	92.7	1,737.2
Playa del Rey	0.65	0.000000025	223,529	129.6	1,724.6

Facility Name	Quantile Level	Contour Level (ug/m3) / (ug/s)	Total population	Area_sqkm	Population density (people/sqkm)
Playa del Rey	0.5	0.000000015	343,059	184.9	1,855.0
Playa del Rey	0.3	0.000000008	521,508	259.1	2,012.4
Pleasant Creek Gas	0.999	0.000008506	0	0.3	0.7
Pleasant Creek Gas	0.99	0.000000623	2	3.6	0.7
Pleasant Creek Gas	0.95	0.000000116	28	17.8	1.6
Pleasant Creek Gas	0.85	0.00000004	6,123	53.3	114.9
Pleasant Creek Gas	0.75	0.000000025	7,413	88.7	83.6
Pleasant Creek Gas	0.65	0.000000018	7,704	124.1	62.1
Pleasant Creek Gas	0.5	0.000000012	8,103	177.4	45.7
Pleasant Creek Gas	0.3	0.000000007	8,502	248.2	34.2
Princeton Gas	0.999	0.00000921	3	0.3	9.5
Princeton Gas	0.99	0.000000628	15	3.5	4.5
Princeton Gas	0.95	0.000000127	35	17.2	2.0
Princeton Gas	0.85	0.000000044	309	51.8	6.0
Princeton Gas	0.75	0.000000027	427	86.3	4.9
Princeton Gas	0.65	0.00000002	472	120.9	3.9
Princeton Gas	0.5	0.000000014	569	172.7	3.3
Princeton Gas	0.3	0.000000009	682	241.6	2.8
Wild Goose Gas	0.999	0.000010589	0	0.3	0.0
Wild Goose Gas	0.99	0.000000742	2	3.4	0.5
Wild Goose Gas	0.95	0.00000016	4	16.7	0.2
Wild Goose Gas	0.85	0.000000056	16	50.1	0.3
Wild Goose Gas	0.75	0.000000035	31	83.4	0.4
Wild Goose Gas	0.65	0.000000025	53	116.6	0.5
Wild Goose Gas	0.5	0.000000018	97	166.6	0.6
Wild Goose Gas	0.3	0.000000013	176	233.0	0.8

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Appendix 1.E. Efforts to Seek Information on Stored Gas Composition

In order to better assess the inventory of chemicals available for release from storage wells during a loss-of-containment (LOC) event, the health impacts team worked with the CCST and the CPUC to make a formal request to each of the storage facility operators for information on stored-gas composition. Contained in this Appendix are (1) a copy of the letter of request we sent out along with (2) the letters of response we received from Southern California Gas (operator of Aliso Canyon, Honor Rancho, La Goleta Gas, Montebello, and Playa del Ray), PG&E (operator of McDonald Island Gas, Los Medanos Gas, Pleasant Creek Gas), Rockport Gas Storage Partners (operator of Kirby Hills, Lodi Gas, and Wild Goose Gas), Central Valley Gas (operator of Princeton Gas), and Gill Ranch LLC (operator of Gill Ranch Gas). As an introduction to these attached materials, we discuss here briefly what we requested and what we got back.

Information we were seeking

As part of the health risk assessment and based on emissions reported and detected from the Aliso Canyon event, we compiled a table of priority chemicals (attached to our request letter below) that we determined would be in the stored gas at trace levels but relevant to public health. Our concern is that these trace constituents could come out with the natural gas during a LOC and might lead to exposures on-site (occupational) or to the nearest off-site community that could exceed health-protection guidelines. But the only way to make this determination is by having knowledge of concentrations of these priority chemicals in the stored gas.

In order to obtain this information, we asked first of the operators: "Please show the proportion of each chemical in parts per billion that is present in the gas after a standard operational withdrawal prior to any processing...." We followed this with a question about detection limits for assessing trace concentrations. If the operator could not fully address the first two questions, we included a third questions that asked why they were not monitoring for these chemicals, what are the barriers to more extensive monitoring, and what would it take to make feasible the monitoring of these chemicals

The responses we received

Although we received responses from all of the operators in California, their responses revealed an absence of both the information we requested and the ability to obtain this information in a timely manner. Some of the responses were terse and somewhat incomplete, others were more detailed but still failed to provide new insight about the current inventory of toxic air contaminants in stored natural gas. In reviewing the responses, it is clear that all of the operators are only currently monitoring for the quality of the gas and the presence of sulfur compounds. None measure for other toxic air contaminants. The operators had different responses with regard to the barriers to more extensive monitoring, and what it would take to make feasible the monitoring of these chemicals. Some indicated that this would involve significant effort and as much as three months of preparation, whereas Rockport Gas Storage Partners stated that they could develop this capacity in about two weeks. Overall, the responses make clear that information on the levels of toxic air contaminants (other than sulfur compounds) will likely not be available without a mandate from the responsible regulatory agency or agencies.

Southern California Gas Company provided a rather detailed response to all the questions but stated that, among the chemicals listed our Tables 1 and 2, they are only currently capable of detecting hydrogen sulfide and mercaptans. They report that they do not routinely test for these compounds but have done spot tests, and they provided tabulated results of the spot tests. They noted limits of detection for hydrogen sulfide and mercaptans of 10 ppb by volume (ppbv) – above both odor thresholds and health-relevant concentrations. With regard to our third question (about why they were not monitoring for these chemicals, what were the barriers to more extensive monitoring, and what would it take to make feasible the monitoring of these chemicals), Southern California Gas had a lengthy answer. Their response noted that they currently only monitor the gas retrieved from the wells for energy content and gas quality. The main barrier to detecting chemicals beyond hydrogen sulfide and mercaptans is the lack of approved on-line analyzers that can monitor all the chemicals in Tables 1 and 2. They estimate that it would take three months just to assess the feasibility of the more extensive chemical sampling.

PG&E reported that they have only limited sampling data collection at their facilities prior to processing. The only non-gas constituents sampled for are hexane, hydrogen sulfide, mercaptans, tetrahydrothiophene, ethyl methyl sulfide, and dimethyl sulfide. Their reported limits of detection are 100 ppbv – significantly above the odor thresholds and health-relevant concentrations. With regard to why they do not monitor for chemicals on our Table 1 and 2, PG&E states that there is no requirement for this, but could make these measurements once they develop the appropriate on-line analyzers—taking about three months.

Rockport Gas Storage Partners responded to the information request by attaching a table showing what analysis methods are commercially available for each of the chemicals listed in our Tables 1 and 2. They did not provide any written response to our questions 1 and 2, but did respond in writing to our question about removing barriers and providing the requested analyses with a list of steps they would take to comply with this information need. They noted it would take them about two weeks to put this capacity in place.

Central Valley Gas Storage (CVGS) responded to the request for sampling data by stating that CVGS has very limited gas-composition-monitoring capability and relies on PG&E to monitor gas composition at a transfer point. CVGS detection limits are based on PG&E detection limits. With regard to barriers and future monitoring capacity, CVGS notes that it would be very expensive to deploy the requested monitoring, and that they would request state support if this were requested.

With the exception of sulfur compounds, Gill Ranch reports that they do not have instrumentation installed to detect low levels of the chemicals listed in our Tables 1 and 2. They monitor once a year for gas composition and for VOC levels (to comply with gas composition rules) and sulfur compounds. They did not provide limits of detection. They report that they do not monitor for chemicals in our Tables 1 and 2, because these chemicals do not have an operational impact, and their detection is not a regulatory requirement. Gill Ranch reports the main barrier to monitoring for these additional chemicals is a study to determine feasibility and cost.

California Public Utilities Commission

Data Request

May 30, 2017

To: Gas storage provider

Re: Chemicals in the natural gas withdrawn from natural gas storage facilities prior to processing.

The information below is being requested for the study on the long-term viability of natural gas storage undertaken by the California Council on Science and Technology pursuant to Senate Bill 826.

Please send the information to [Address specified] no later than June 13, 2017. Call (Number specified) regarding any questions.

++

Note: The term “chemicals” used below refers to the items listed in the tables shown in the appendix. The chemicals in Table 1 are considered high priority for the study. The CASRN column in the tables refers to the Chemical Abstracts Service Registry Number.

1) Please show the proportion of each chemical in parts per billion that is present in the gas after a standard operational withdrawal prior to any processing to bring the gas to utility pipeline standards from each well at the underground gas storage facility or facilities you operate in California. In your response, confirm that the data was taken from samples prior to any processing after the withdrawal.

2) Describe the limits of the capability of your monitoring instrumentation to detect the chemicals. What is the minimum quantity of the chemicals that your instrumentation can detect?

3) If you are not monitoring any of the chemicals,

a) Explain why the chemicals are not being monitored.

b) Describe any barriers that exist for monitoring the chemicals.

c) How soon could the barriers be removed and the requested data provided for the Table 1 and the Table 2 chemicals?

Table 1.E-1. Priority chemicals relevant to underground gas storage in California designated as 'must have' (n=16).

CASRN	Chemical Name
106-99-0	1,3-Butadiene
75-07-0	Acetaldehyde
107-02-8	Acrolein
7664-41-7	Ammonia
71-43-2	Benzene
56-23-5	Carbon tetrachloride
50-00-0	Formaldehyde
7783-6-4	Hydrogen sulfide
74-93-1	Mercaptan, Methyl
75-08-1	Mercaptan, Ethy
75-33-2	Mercaptan, Isopropyl
75-66-1	Mercaptan, t-Butyl
107-03-09	Mercaptan, Propyl
91-20-3	Naphthalene
127-18-4	Perchloroethylene
108-88-3	Toluene

Table 1.E-2. Additional priority chemicals relevant to underground storage in California (n=33).

CASRN	Chemical Name
71-55-6	1,1,1-Trichloroethane
95-63-6	1,2,4-Trimethylbenzene
7440-38-2	Arsenic
7440-41-7	Beryllium
7440-43-9	Cadmium
7782-50-5	Chlorine
18540-29-9	Chromium (VI)
108-90-7	Chlorobenzene
67-66-3	Chloroform
7440-50-8	Copper
106-93-4	Ethylene dibromide
107-06-2	Ethylene dichloride
107-21-1	Ethylene glycol
110-54-3	Hexane
7647-01-0	Hydrochloric acid
7439-96-5	Manganese
7439-97-6	Mercury
67-56-1	Methanol
75-09-2	Methylene chloride
7440-02-0	Nickel
108-95-2	Phenol
115-07-1	Propylene
75-56-9	Propylene oxide
129-00-0	Pyrene
7782-49-2	Selenium
7631-86-9	Silica, Crystalline
1310-73-2	Sodium Hydroxide
100-42-5	Styrene
79-01-6	Trichloroethylene
1330-20-7	Xylenes
108-38-3	m-Xylene
95-47-6	o-Xylene
106-42-3	p-Xylene

Appendix 1.F. Operator Response Letters

Please see website: http://ccst.us/projects/natural_gas_storage/correspondence.php

Appendix 1.G. Best Practices in Occupational Safety and Health

There are numerous publications on best practices, or recommended practices in occupational safety and health to guide organizations wishing to improve their record in these areas. One mentioned here was developed at the request of industry ("Driving Toward '0': Best Practices in Corporate Safety and Health") and another is a recent OSHA publication ("Recommended Practices Safety and Health Programs"). While there are also numerous publications on best practices for pipelines and underground gas storage, most are focused on the integrity of the system and not on occupational health and safety specifically, e.g., Protecting our Infrastructure of Pipelines and Enhancing Safety (PIPES) Act of 2016. The UGS industry is encouraged to tailor the occupational health and safety best practices to protect workers in underground gas storage processes.

In their report, "Driving Toward "0": Best Practices in Corporate Safety and Health" Whiting and Bennett (2003) discuss a direct response to requests by members of the Conference Board's Townley Center for Environment, Health, and Safety Councils—a long-established networking group of senior EH&S executives from approximately 65 leading US companies—for a benchmark on corporate safety culture and a rating of the policies and best practices that affect corporate safety performance." Some of the key findings of this report include the following:

> **Leadership at the top** *If the top executive believes in the worth of the strategies, sets expectations for other managers, follows through on those expectations, and commits appropriate resources, shared beliefs, norms, and practices will evolve.*
>
> **Confidence on the part of all employees** *that the company values safety and health comparably with other values, and an understanding by all employees of how to achieve the expected performance. Everyone must be committed and engaged.*
>
> **Creating and implementing a safety and health management system that works for the individual company.**
>
> **Monitoring performance regularly** *Companies must continually assess their norms and provide frequent feedback to all employees and to external stakeholders.*
>
> *Use of the best practices included in the survey is high — 84% of surveyed companies have adopted all 23 strategies listed in the survey. (The complete survey form can be found at the end of the report.) Although comments on preferred practices reveal considerable variation as to what practices companies emphasize most—reflecting a variety of specific risks and challenges, as well as 'cultural' differences in approach—certain themes stand out as essential:* **Clear management visibility and leadership** *Ownership of safety and health by all employees—moving from "involvement" to 'empowerment'.*

> **Accountability at all levels of an organization***, including positive and negative performance feedback*

Open sharing of knowledge and information throughout the organization

> *If there are similar core principles in play at companies striving toward '0,' there is no common template. Each company faces unique needs and opportunities inherent in the nature of its operations and workplaces, and from whatever company culture is brought to bear.*
>
> *Operational integration, defined in the survey as "the integration of safety into all facility operations and processes"—and the most highly rated practice in the survey—has been adopted by 90 percent of respondents. The practice was given an effectiveness rating of 8 or better by more than 75 percent of its users, and almost 30 percent gave it a rating of 9 or 10, putting it in the 'extremely effective' category.*
>
> *Ratings for some of the more traditional programs, such as safety committees and training, were less positive than might be expected. This may be because respondents were familiar with these safety and health management tools, since companies have employed them for decades; it may also suggest that respondents viewed these programs more as necessary obligations than best practices.*
>
> *Strategies to increase employee involvement beyond the established use of safety committees may prove the most fertile ground for further improvement of safety and health performance, especially in light of the current emphasis on employee ownership as a vital component of any safety and health program*

More recently, OSHA (2016a) published a report entitled, "Recommended Practices Safety and Health Programs." In this report, OSHA (2016a) identified seven core elements as recommended practices for managing occupational safety and health; these emphasize a proactive approach, in contrast to traditional approaches, which are often reactive. The following is quoted from the OSHA (2016a) document:

CORE ELEMENTS OF THE SAFETY AND HEALTH PROGRAM RECOMMENDED PRACTICES

1. **Management Leadership**

- Top management demonstrates its commitment to continuous improvement in safety and health, communicates that commitment to workers, and sets program expectations and responsibilities.
- Managers at all levels make safety and health a core organizational value, establish safety and health goals and objectives, provide adequate resources and support for the program, and set a good example

2. **Worker Participation**

- Workers and their representatives are involved in all aspects of the program—including setting goals, identifying and reporting hazards, investigating incidents, and tracking progress.
- All workers, including contractors and temporary workers, understand their roles and responsibilities under the program and what they need to do to effectively carry them out.
- Workers are encouraged and have means to communicate openly with management and to report safety and health concerns without fear of retaliation.
- Any potential barriers or obstacles to worker participation in the program (for example, language, lack of information, or disincentives) are removed or addressed.

3. **Hazard Identification & Assessment**

- Procedures are put in place to continually identify workplace hazards and evaluate risks.
- Safety and health hazards from routine, nonroutine, and emergency situations are identified and assessed.
- An initial assessment of existing hazards, exposures, and control measures is followed by periodic inspections and reassessments, to identify new hazards.
- Any incidents are investigated with the goal of identifying the root causes.
- Identified hazards are prioritized for control.

4. **Hazard Prevention & Control**

- Employers and workers cooperate to identify and select methods for eliminating, preventing, or controlling workplace hazards.
- Controls are selected according to a hierarchy that uses engineering solutions first, followed by safe work practices, administrative controls, and finally personal protective equipment (PPE).
- A plan is developed to ensure that controls are implemented, interim protection is provided, progress is tracked, and the effectiveness of controls is verified.

5. **Education & Training**

- All workers are trained to understand how the program works and how to carry out the responsibilities assigned to them under the program.
- Employers, managers, and supervisors receive training on safety concepts and their responsibility for protecting workers' rights and responding to workers' reports and concerns.
- All workers are trained to recognize workplace hazards and to understand the control measures that have been implemented

6. **Program Evaluation & Improvement**

- Control measures are periodically evaluated for effectiveness.
- Processes are established to monitor program performance, verify program implementation, and identify program shortcomings and opportunities for improvement.
- Necessary actions are taken to improve the program and overall safety and health performance.

7. **Communication and Coordination for Host Employers, Contractors, and Staffing Agencies**

- Host employers, contractors, and staffing agencies commit to providing the same level of safety and health protection to all employees.
- Host employers, contractors, and staffing agencies communicate the hazards present at the worksite and the hazards that work of contract workers may create on site.
- Host employers establish specifications and qualifications for contractors and staffing agencies.
- Before beginning work, host employers, contractors, and staffing agencies coordinate on work planning and scheduling to identify and resolve any conflicts that could affect safety or health.

Below are definitions of key terms in OSHA (2016a):

> **Host employer:** *An employer who has general supervisory authority over the worksite, including controlling the means and manner of work performed and having the power to correct safety and health hazards or require others to correct them.*

Contractor: *An individual or firm that agrees to furnish materials or perform services at a specified price, and controls the details of how the work will be performed and completed.*

Staffing agency: *A firm that provides temporary workers to host employers. A staffing agency hires its own employees and assigns them to support or supplement a client's workforce in situations involving employee absences, temporary skill shortages, seasonal workloads, and special projects.*

Temporary workers: *Workers hired and paid by a staffing agency and assigned to work for a host employer, whether or not the job is actually temporary.*

The new guidelines call for employers to take proactive steps in seven different areas:

- **Management Leadership** — OSHA recommends employers draft a communication policy to comport management expectations around defined goals, allocate resources for the project, and set a good example for workers through management embrace of the initiative.

- **Worker Participation** — Calls for employers to provide opportunities for workers to participate in a safety program, and to ensure they have access to all information they need in order to participate.

- **Hazard Identification and Assessment** — Prompts employers to collect and review hazard information, identify trends, conduct internal workplace safety inspections, investigate injuries or illnesses, and more.

- **Hazard Prevention and Control** — Calls for employers to proactively identify and evaluate hazard control tools, as well as their effectiveness, and to develop emergency plans for workers.

- **Education and Training** — Calls for employers to train workers on safe practices for their workplaces, to verify that training, and to ensure specialized training is provided for certain unique hazards.

- **Program Evaluation and Improvement** — Calls for employers to establish metrics to determine whether or not their safety programs are effective, and to identify and act upon opportunities for continuous improvement.

- **Coordination and Communication on Multiemployer Worksites** — Sticking with OSHA's recent attention to workplaces with workers from more than one business, this step asks employers to ensure that *all* workers present are brought in on safety initiatives, trainings, assessments, and hazard prevention programs.

Process Safety Management (PSM) Standards Recognized and Generally Accepted Good Engineering Practices (RAGAGEP) Requirements

The PSM Standard, 29 CFR 1910.119, directly references or implies the use of RAGAGEP in three provisions (OSHA 2016b):

- **(d)(3)(ii):** Employers must document that all **equipment** in PSM-covered processes complies with RAGAGEP;
- **(j)(4)(ii): Inspections and tests** are performed on process equipment subject to the standard's mechanical integrity requirements in accordance with RAGAGEP; and
- **(j)(4)(iii):** Inspection and test **frequency** follows manufacturer's recommendations and good engineering practice, and more frequently if indicated by operating experience.

In addition, **(d)(3)(iii)** addresses situations where the design codes, standards, or practices used in the design and construction of existing equipment are no longer in general use. In such cases, the employer must determine and document that the equipment is designed, maintained, inspected, tested, and operating in a safe manner.

As used in the PSM standard, RAGAGEP apply to process equipment design and maintenance; inspection and test practices; and inspection and test frequencies.

"Recognized and generally accepted good engineering practice," a term originally used by OSHA, stems from the selection and application of appropriate engineering, operating, and maintenance knowledge when designing, operating and maintaining chemical facilities with the purpose of ensuring safety and preventing process safety incidents.

It involves the application of engineering, operating or maintenance activities derived from engineering knowledge and industry experience based upon the evaluation and analyses of appropriate internal and external standards, applicable codes, technical reports, guidance, or recommended practices or documents of a similar nature. RAGAGEP can be derived from singular or multiple sources and will vary based upon individual facility processes, materials, service, and other engineering considerations.

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Chapter 2

Does California Need Underground Gas Storage to Provide for Energy Reliability through 2020?

ABSTRACT

This chapter addresses whether or not California needs underground gas storage to provide reliability for the near-term, i.e. through 2020. The chapter describes the natural gas transmission and distribution systems that serve California, the current and evolving role of underground gas storage in preserving reliable natural gas and electricity service in California and possible alternatives to underground gas storage that would preserve that reliability. A copy of the scope of work is contained in Appendix B.

1.0 The California Gas System

California's pipeline capacity and underground gas storage facilities give California consumers diverse options for supply and operational flexibility that most states do not have and have successfully served California's natural gas demand requirements except for a handful of instances.[1] Approximately 85% of the gas used in California comes from out-of-

1. The State routinely assesses the adequacy of the pipeline and storage capability relative to demand. For example, the two large gas utilities, Southern California Gas Company (SoCalGas) and Pacific Gas and Electric Company (PG&E), presented a joint assessment to the CPUC in support of accessing new gas supply in 1961 (see CPUC Decision No. 6226). Every two years these utilities continue to present an updated assessment in the California Gas Report (CGR). The California Energy Commission (CEC) conducts assessments and outlooks for natural gas, often in conjunction with its Integrated Energy Policy Report (IEPR), augmented sometimes by the Research and Development Division. The CPUC has also presented various assessments. See, for example, MRW & Associates, "Natural Gas Storage in California," 2007 http://www.energy.ca.gov/research/notices/2007-11-15_workshop/presentations/MRW+associates_NG_Storage_in_CA.pdf (Accessed March 2017). See Also ICF, "The Value of Natural Gas Storage and the Impact of Renewable Generation on California's Natural Gas Infrastructure." CEC Energy Research and Development Division Final Project Report, CEC 500-2013-131, 2009 (Accessed March 2017). And Myers, Khosrowjah and Hendry "California Natural Gas Infrastructure Outlook," CPUC Energy Division Staff Report November 2001, found at http://docs.cpuc.ca.gov/published/report/natural_gas_report.htm#P679_36190 (Accessed May 2017).

state sources.[2] Interstate pipelines serving California include Gas Transmission Northwest, El Paso, TransWestern, Kern River, Ruby, Southern Trails, Paiute and Tuscarora pipelines. Figure 1 displays the supply basins and connecting high pressure transmission pipelines that deliver natural gas to California, or that otherwise have an impact on California markets. These supply basins include the Western Canadian Sedimentary Basin in Alberta, the "Rockies" basins centered in southwestern Wyoming, the San Juan basin of northwestern New Mexico, the Permian basin of west Texas and, in years past, even the Texas/Oklahoma Panhandle's Anadarko basin. Some of these basins are more than 1,000 miles away from California's key population centers. The pipelines between the producing areas and California also serve markets outside of California. Virtually all the gas that comes into California stays in California, where it is either consumed immediately or put into storage to consume later.

SoCalGas and PG&E serve most, but not all, of the State's gas consumers. SoCalGas and PG&E own and operate approximately 9,830 miles of high pressure transmission lines inside the State that interconnect with the interstate pipeline delivery points at the southeastern and northern borders of the State. PG&E and SoCalGas deliver gas from the transmission lines to end-use customers through their distribution systems (see Figure 3).[3, 4]

2. Production occurs in both northern and southern California. The wells in southern California tend to produce primarily oil, with a small amount of hydrocarbon output in the form of natural gas; wells in northern California, in contrast, tend to produce only natural gas.

3. The 9,830 miles is compiled from the 2015 and 2016 Form 10-K reports filed with the Securities and Exchange Commission by Sempra (parent company of SoCalGas and SDG&E) and PG&E, respectively. SoCalGas and PG&E were the largest two natural gas utilities in the U.S., in terms of number of customers. SoCalGas delivered more gas to customers than any other gas utility, while PG&E ranked second (see American Gas Association, Statistics Database 2015 Ranking of Companies, at https://www.aga.org/sites/default/files/1002totcust.pdf).

4. Most end-use customers receive gas at the distribution level (which consists of smaller-diameter pipes that operate at pressures of less than 60 psig). Some large customers, however, receive gas from larger pipelines at pressures that qualify as transmission level (i.e., they are larger-diameter pipe that operate at higher pressures). See, for example, Pacific Gas and Electric 2017 Gas Rate Finder, Volume 45-G, No. 4. April 2017. Online: https://www.pge.com/tariffs/GRF0417.pdf (Accessed July 2017).

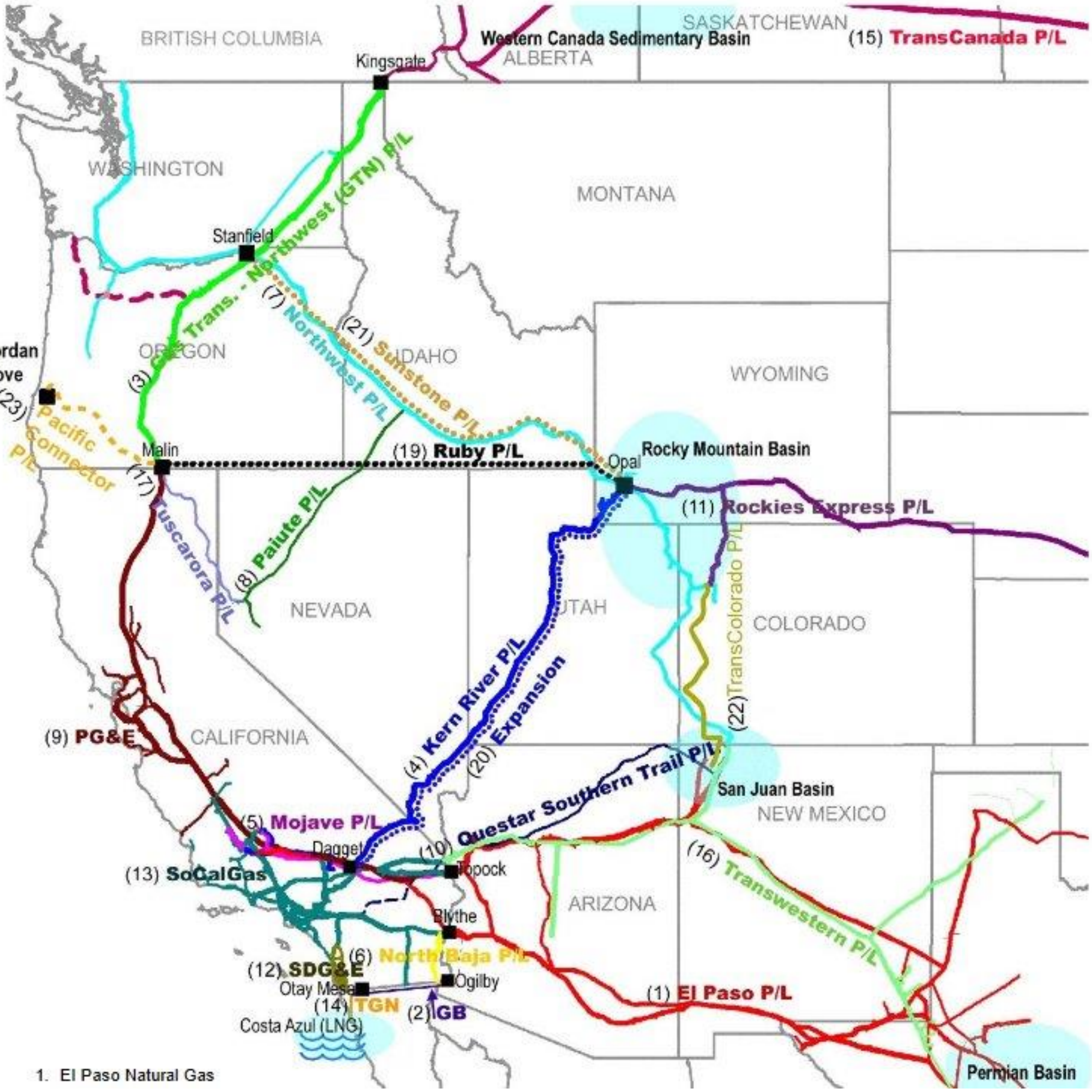

Figure 1. Western Gas Pipelines and Supply Basins Serving California
Source: California Gas Report

Pipelines that come in from the receipt points at the state lines do not all connect to each other within the State.[5] However, customers can buy gas from any supply area connected by the interstate pipelines to the intrastate system whether or not they have a direct connection to that supply.[6]

The 12 depleted gas or oil fields used to store gas underground are an essential element of the intrastate pipeline and distribution gas delivery systems in meeting peak seasonal natural gas demand in California. With a capacity of 375 bcf, six companies operate these fields pursuant to the Public Utilities Code of the State of California under certificates granted by the California Public Utilities Commission (CPUC). PG&E and SoCalGas each own and operate four facilities comprising approximately 60% of the total storage capacity.

No other state has such a diversity of supply access and storage capability. Through this system, California has the flexibility to augment pipeline gas with stored gas. Local gas distributors in states without storage have to pay for firm interstate pipeline capacity that is used only in peak months or restrict deliveries of natural gas to non-core customers in winter demand months.[7] And many pipelines are not connected to underground gas storage.[8] Figure 6 shows the locations of some 400 facilities nationwide that can store over 4,700 Bcf of gas across the country. Additional large gas storage facilities are also located in Ontario and Alberta, Canada.

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5. Other aspects of the pipeline system constrain the flow such as the physical capacity of the pipes, flow direction conflicts, constraint points, and lack of interconnection between the pipelines. The direction of physical flow is generally from the state line towards the load centers. Gas from Canada and the Rockies arrives at Malin, Oregon and flows south. Gas from the Rockies can also flow southwesterly from Wyoming towards Las Vegas and enter California there, crossing the Mojave Desert and terminating at Bakersfield. Gas from the San Juan Basin flows in at Topock, Arizona (Needles, CA), from which one pipeline continues on to Los Angeles (LA) and another moves towards Barstow, then Bakersfield and turns north. From there it crosses over to the Highway 101 corridor and terminates at Milpitas. Gas from the Permian Basin flows in at Ehrenberg, Arizona and continues across the desert to Moreno Valley and on into the southern portion of the LA Basin.

6. Customers can buy gas through an "exchange displacement" process which allows a customer located in Redding to buy gas from Texas or a customer in southern California to buy Canadian gas supply. For example, PG&E physically delivers gas from Canada that was purchased by customers of SoCalGas or SDG&E to its customers in northern California. PG&E replaces that gas by delivering to SoCalGas an equivalent amount of gas from the Southwest. PG&E's displacement capability is limited to the quantity of gas that can be transferred through the Kern River Station.

7. For a long time, Indiana had restrictions on new non-core customers using gas in winter months. Massachusetts is another example. Pipeline tariffs there used to offer a seasonal firm service: firm in summer and interruptible in winter. See also Tussing and Teepee (1995), p. 122.

8. See Aspen's 2010 "Implications of Greater Reliance on Natural Gas for Electricity Generation," p. 62, for a list (that may need updating) of pipelines not connected to underground gas storage.

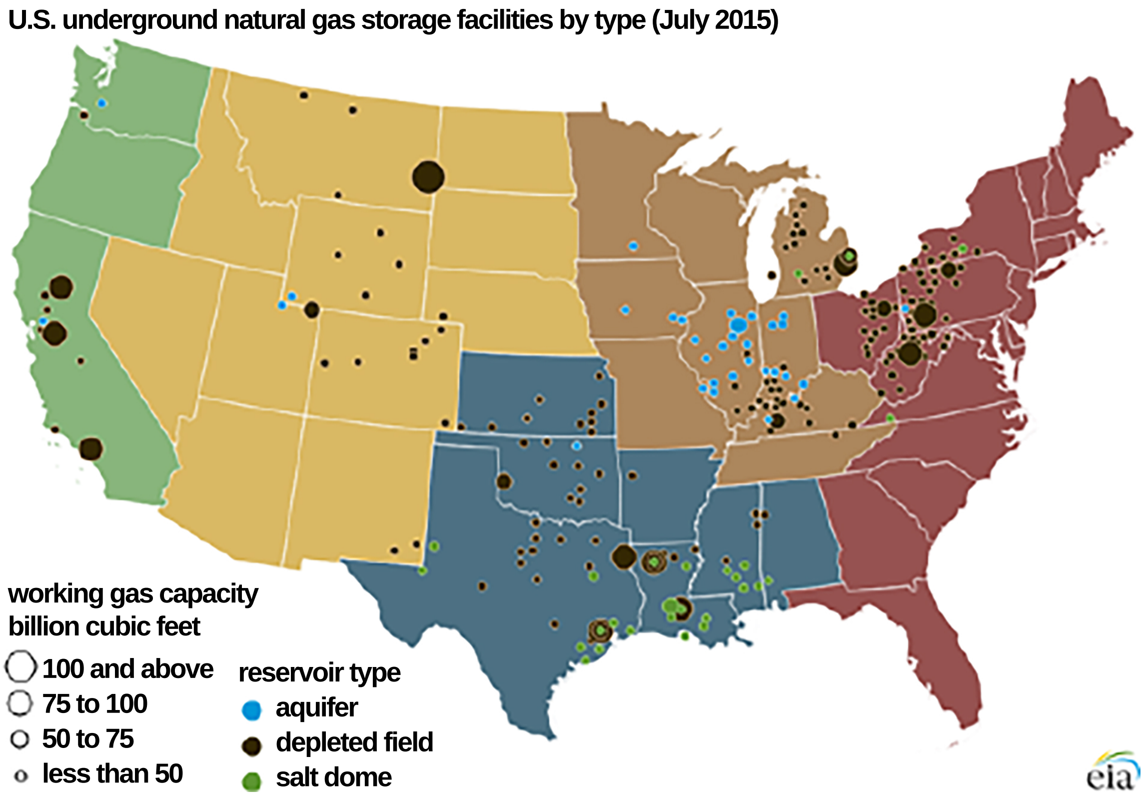

Figure 2. U.S. Underground Gas Storage Facilities
Source: Energy Information Administration

Figure 3 displays the general location of the various in-state underground gas storage facilities relative to the gas transmission system in California. SoCalGas owns all the storage in southern California. PG&E owns some of the storage they use in northern California, but "independently operated" gas storage also plays a role.[9] The Legislature explicitly encouraged independent gas storage to help create open and competitive markets for storage services. In this respect, gas utilities do not control any aspect of independent gas operations. The Legislature also encouraged unbundling, or separation of storage costs from the rates charged by public utilities for services such as gas transportation or supply sales.[10]

9. Several types of companies own natural gas storage facilities, including utilities, pipeline operators, and dedicated storage owners. Some storage facilities are owned by utilities who use them to meet their customers' needs. The majority of storage facilities in the U.S. are owned and operated by pipeline and independent service providers who lease their use to large end-use customers or third-party shippers.

10. AB 2744 (Costa) Chaptered 1992.

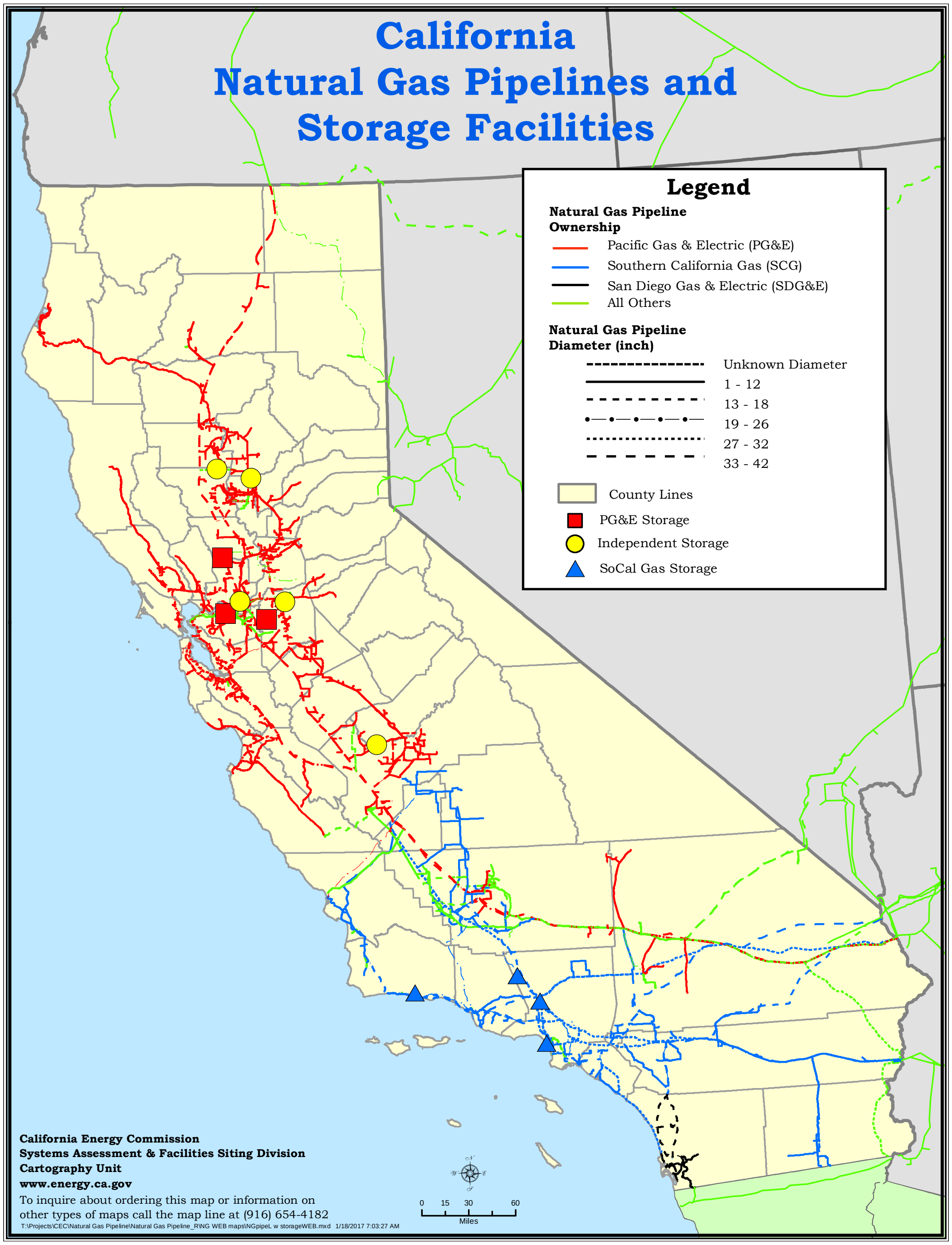

Figure 3. General Layout of California High Pressure Pipeline and Storage Facilities
Source: California Energy Commission

1.0.1 Customer Types

The regulatory framework for the transportation, storage, distribution and sale of natural gas in California separates gas supply service from transportation service and splits customers into core and non-core customers.[11] Residential and small commercial customers are deemed "core" customers. The utility provides core customers with gas supplies, transmission, storage, distribution, metering, and billing all "bundled" into one package. The CPUC does not allow the utilities to add any mark-up or profit to the commodity cost of the gas supply. Instead, utilities earn an allowed rate of return, approved by the CPUC, on the physical assets they own, such as pipelines, distribution lines, compressor stations, and storage facilities.[12]

The remaining customers are deemed "non-core." As defined by the CPUC, non-core customers are those that annually consume a threshold quantity of 250,000 therms of gas annually, which equates to about 25 MMcf (CPUC Decision Nos. 86-12-010 and 90-09-089). Under rules adopted in 1986 and revised in 1990, the CPUC does not permit the gas utilities it regulates to procure gas supply and re-sell it to non-core customers (CPUC Decision Nos. 86-12-010 and 90-09-089). Instead, non-core customers must buy their own gas. The utilities provide non-core customers with transportation service, meaning that the utility simply delivers to the customer the amount of gas that the customer purchased elsewhere.[13]

11. This basic breakdown was adopted by the CPUC in D. 86-12-010 and implemented May 1, 1988. The CPUC regulates rates and the terms of service provided by PG&E, SoCalGas, SDG&E, and Southwest Gas Company. Several municipalities operate gas utilities, including the cities of Long Beach, Palo Alto, and Coalinga. These gas utilities receive transmission service from PG&E and SoCalGas, respectively, depending on their location. SDG&E has a very short summary of the initial implementation and key developments at http://www.sdge.com/customer-choice/natural-gas/history-gas-choice-and-definitions.

12. Bills to core customers, nonetheless, typically break out and show the commodity cost of gas supply (that the utility procures on behalf of core customers) separately from the cost of delivery.

13. The CPUC requires transportation service to non-core customers be provided on a non-discriminatory basis. This means that any customer willing to pay the CPUC-approved rate and abide by the applicable tariffs for service must be provided service under those stated terms and conditions. Those terms and conditions also specify rules for prioritizing service when capacity or supply become constrained. More specifically, it means that the utility is not allowed to block market access or discriminate in providing information among market participants. The utility staff that procure gas supply on behalf of core customers (often referred to as the "core procurement group") are considered to be market participants and thus are sequestered from the transportation operations staff. An information firewall must be maintained between those employees who perform functions related to the distribution business and those employees who are involved with the sale of gas.

Both core and non-core customers have equal access to gas transmission capacity. However, the California gas utilities curtail non-core customers first in the event of a gas supply or a gas capacity shortage for several reasons. First, only core customers are entitled to firm uninterruptible service[14] because of the high cost and safety issues involved in restoring service after a curtailment. The recovery process requires a house to house, block by block effort to purge individual distribution lines and services of any air and water that might have invaded the gas lines during an outage and to relight pilot lights and restart gas appliances. Recovery can take several days depending on the number of customers. Second, the gas delivery system was sized to serve only core customers on a very cold day. Finally, because fewer system costs are allocated to non-core customers, they pay a lower rate for gas transportation service than the rates charged to core customers. The CPUC adopted this framework at a time when non-core customers could burn alternate fuels when natural gas was not available.[15] Now regulatory requirements governing air emissions mean that most large non-core gas customers cannot easily switch to an alternate fuel leaving fewer options to maintain operations. So, while non-core customers are, by definition, interruptible, California essentially provides firm service
to all customers.

1.0.2 Gas Flows To and From the Receipt Points

If full, the interstate pipelines that connect to PG&E and SoCalGas can bring 10,360 MMcf to the state line each day.[16] With a few exceptions, these interstate pipelines terminate at the state line where they interconnect with one or both of California's two large local distributors, PG&E and SoCalGas.[17] Most load is served by local distribution companies, but not all; and most decisions about capacity in California are made by the CPUC, but not all. [18,]

14. "Firm" means never interrupted.

15. This framework goes back to the Natural Gas Policy Act of 1978 that required states to develop end-use priority rules after the gas service curtailments in Midwestern states such as Indiana, Illinois and Ohio during the very cold winter of 1976-77.

16. The industry commonly describes the capacity of a pipeline in terms of what it can deliver in a 24-hour period and describes this as MMcf per day or MMcfd.

17. Gas Transmission Northwest terminates at Malin, Oregon and PG&E takes over. TransWestern Pipeline terminates at Topock, Arizona/Needles, CA and interconnects with PG&E and with SoCalGas there. El Paso Natural Gas' northern mainline terminates at Topock and interconnects there with PG&E and SoCalGas. El Paso's southern mainline terminates at Topock and feeds into SoCalGas (and the North Baja pipeline that can feed Mexico). PG&E and SoCalGas add odorant to the gas at the receipt points where they take the gas from the interstate pipelines.

18. Some customers of Southwest Gas (which has small amounts of non-contiguous service area along the edges of the State and elsewhere) are served via connection from other interstate pipelines, such as those in the Lake Tahoe area served from Nevada via Paiute Pipeline.

[19, 20, 21] The interstate pipelines serving California are shown in Figure 3.

19. Gas entering the PG&E or SoCalGas systems becomes subject to the regulatory jurisdiction of the CPUC (which has adopted PHMSA DOT 192 as its standard for safety, risk, and pipeline integrity regulation). The CPUC regulates not in addition to, but in lieu of, the Federal Energy Regulatory Commission (FERC). FERC, nonetheless has ways of influencing California. California participates in the rate cases of the interstate pipelines upstream of California. FERC also approves the tariff of the CAISO, which includes treatment of certain aspects of gas cost recovery in electricity markets. The principal of open access, non-discriminatory transportation service that applies under FERC pipeline regulation is similar to that adopted in California.

20. This occurs as the result of a 1954 amendment to 1938's federal Natural Gas Act called the "Hinshaw Amendment." Absent the Hinshaw amendment, one would expect the high-pressure transmission portion of the PG&E and SoCalGas systems to be regulated by FERC as interstate pipelines that would drop off gas to local distribution companies regulated by the CPUC. The Hinshaw Amendment was enacted by Congress after the U.S. Supreme Court ruled that out-of-state gas carried by an intrastate pipeline affiliate of a gas distribution company in Ohio (East Ohio Gas) that delivered all of that gas to the local distribution company (LDC), which then re-delivered it only to the LDC's retail customers, was operating in interstate commerce, and thus subject to regulation under the Natural Gas Act by the Federal Power Commission. With the Ohio situation being analogous to the situation of PG&E and SoCalGas bringing gas from the State line to their retail end-use customers, SoCalGas (then known as Pacific Lighting) turned to southern California House member Carl Hinshaw for legislative relief. The amendment he sponsored exempts a pipeline receiving gas in interstate commerce from FERC regulation if the state regulates the pipeline's rates, services, and facilities and if the gas received is consumed entirely within the receiving state. California's PG&E and SoCalGas meet this two-pronged test of the Hinshaw amendment, namely, the gas that comes in is consumed in California and the rates, services, and facilities are regulated by the CPUC. In federal regulatory proceedings, PG&E and SoCalGas are sometimes referred to as "Hinshaw pipelines." FERC interprets the Hinshaw exemption from federal regulation to be an option exercised at the request of a facility applicant, and not a requirement a state can impose. For example, the Mojave Pipeline and Kern River Gas Transmission (or "Kern River" pipeline) which crosses from Nevada into California and continues on to its terminus around Bakersfield did not seek permission to construct and operate in California from the CPUC. Instead, it sought certification only from FERC and proposed to operate the entire pipeline as a federally regulated pipeline, with that federal status continuing to the pipeline's terminus well into California. Such permission is sought via application for a certificate of public convenience and necessity (CPCN) or simply "certificate." Kern River's certificate was granted by FERC at: CP89-2047-000 et al. (Jan. 24, 1990); Mojave's at 47 FERC ¶ 61,200 (1989).") The CPUC, PG&E, and SoCalGas opposed FERC's granting of Certificate of Public Convenience and Necessity (CPCN) to Mojave and Kern River. While SoCalGas settled with the pipelines, the CPUC and PG&E did not. FERC approved the settlement and granted the CPCNs, leading the California parties to challenge the CPCNs in federal court. The court ruled in favor of FERC and the Kern River. Another example of a FERC-jurisdictional pipeline operating in California is Tuscarora, which interconnects with Gas Transmission Northwest at Malin and crosses the northeastern high desert of California, serving customers in towns such as Susanville, on its way to Reno.

21. Mojave pipeline was a joint venture between El Paso Natural Gas and TransWestern Pipeline to bring southwest gas across the State line and directly serve the enhanced oil recovery (EOR) fields in Kern County. Kern River was a competing project to bring Rockies production to Kern County. Chevron USA, which was both an EOR producer in Kern County and a gas producer in the Rockies, eventually signed on as a shipper with Kern River. Kern River, Mojave and SoCalGas agreed, in a settlement approved by FERC, that both Kern River and Mojave would build from their respective starting points (in different supply basins) to a point near Barstow. At that point, the two pipelines would merge and continue on to the Bakersfield area. The agreement gave SoCalGas an option to purchase the California portion of Kern and Mojave 20 years after startup, which would have been 2013. EPNG bought out Enron's share of Mojave in 1993.

Table 1. Interstate Pipelines Serving California.

Pipeline	Firm Capacity (MMcfd)	Year First Online*
Gas Transmission Northwest	2,090	1961[1]
El Paso Natural Gas Company	3,770	1948
TransWestern Pipeline Company	1,185	1960
Kern River Gas Transmission	1,735	1992[2]
Ruby Pipeline	1,500	2011
Southern Trails	80	2003[3]
SubTotal Connected to PG&E and SoCalGas*	10,360	
Additional Pipelines Serving Outlying Areas		
Paiute Pipeline Company	41	1988[4]
Tuscarora Gas Transmission Company	230	1995
GRAND TOTAL[5]	10,631	

1 Originally known as Pacific Gas Transmission; constructed and owned by PG&E. PGT was sold to TransCanada Pipelines Limited in 2004. See http://www.csrreport.transcanada.com/docs/Investor_Centre/aif_2005_TCPL_eng.pdf (Accessed March 2017).

2 Kern River Gas Transmission was originally a partnership between the Williams Companies and Tenneco. It was sold to Berkshire Hathaway in 2002.

3 Southern Trails was purchased by Questar from ARCO in 1998. Then known as ARCO's Line 90, it was constructed in 1957 as an oil pipeline and ran from the Four Corners area to Long Beach. Questar intended to convert it to natural gas service for its entire length, hoping to pick up load that sought alternatives to SoCalGas. SoCalGas and others argued the "bypass" of its facilities would be uneconomic, leading the CPUC to approve SoCalGas tariffs that effectively penalized customers who took service from Southern Trails if they also maintained a connection to SoCalGas. Effectively killing the intended market, Questar ultimately converted only 488 miles. Southern Trails interconnects with SoCalGas at North Needles and terminates at Essex, California with an interconnection to PG&E. Questar's website states its intention to sell the remaining mileage by the end of 2017. See https://rbnenergy.com/taxonomy/term/1626/feed; https://www.gpo.gov/fdsys/pkg/FR-1999-03-22/html/99-6839.htm; http://www.prnewswire.com/news-releases/questar-pipeline-completes-purchase-renames-line-90-pipeline-77523932.html and https://www.sec.gov/Archives/edgar/data/764044/000091205702012527/0000912057-02-012527.txt (pp. 5-6) for more on this pipeline over the years.

4 Paiute crosses from Nevada to serve the Lake Tahoe area; it does not connect to PG&E or to SoCalGas.

5 The grand total shown includes capacity that enters or crosses California (Paiute and Tuscarora) but serves load such as that in Reno, it is therefore generally excluded from the remainder of this analysis.

Source: Compiled from various sources by Aspen Environmental Group

History of SoCalGas, CPUC Decision No. 62260, FERC Calendar Files

** The first year online is very close to date of original construction; additional facilities may have been added later.*

Although the interstate pipelines can deliver 10.3 Bcf per day to the state, PG&E and SoCalGas do not have the capacity to receive and transport that much gas to their load centers. Table 2 shows the amount these utilities can receive, known as "receipt point capacity" or "take-away capacity."

As of 2017, PG&E can take a total of slightly over 3 Bcf per day through a system of high pressure transmission lines connecting to receipt points at Malin, Kern River Station, and Topock. In theory, SoCalGas can take 3.875 Bcf per day, but various factors reduce this amount. For example, SoCalGas has voluntarily reduced the operating pressure on its Line 2000 that runs from Ehrenberg through Moreno Valley into the southern part of the LA Basin until it completes hydrostatic testing of the pipeline.[22] This lower operating pressure reduces Line 2000's effective transportation capacity by 200 MMcfd, as captured in Table 2. Also, although SoCalGas has the pipeline capacity to take a total of 310 MMcfd from California natural gas producers located along the coast or in the San Joaquin Valley, production from those sources has declined, and recently only about 60 MMcfd has been delivered for sale to utility customers. Utility forecasts and producers do not cite any expectation for recovery and consequently, this analysis discounts the capacity down to the expected supply. In calculating the rate that gas can be delivered in California, we use the take-away capacity unless the available supply at any receipt point is consistently and significantly less than that capacity.[23, 24, 25]

22. Required under the post-San Bruno remediation measures. SoCalGas' Envoy system lists the end date for the voluntary maximum operating pressure as "TBD."

23. The CEC's 2015 Natural Gas Outlook projected that California natural gas production would continue to decline. The 2016 California Gas Report used 122 MMcfd, stating it was the average supply delivered to it from California sources in 2015 (2016 CGR, p. 79). The Joint Agency technical assessments use 60 MMcfd. An analysis of scheduled quantities reported on SoCalGas' Envoy web site supports use of the 60 MMcfd.

24. SoCalGas also has work on its Line 3000 at Topock that further reduces its take-away capacity by about 250 MMcfd. This situation should be short-term and is not therefore reflected in the adjusted estimate of 3.425 MMcfd in take-away capacity.

25. Additionally, Kern River delivers gas directly to end-users, many of which are located in Kern County in addition to making deliveries to PG&E's Line 300 and to SoCalGas' Line 225 at Wheeler Ridge (or at Kramer Junction, into the main line coming in from Topock) (Kern River Gas Transmission Company, 2015). Reflecting typical deliveries to PG&E and to SoCalGas, the net remaining capacity delivering gas directly to end users should be close to 835 MMcfd. The exact value for what Kern River delivers to California may decline over time as upstream markets use more of Kern River's capacity; data in their 2017 customer meeting presentation shows that is already happening. The customer meeting presentation can be found at: http://services.kernrivergas.com/portal/DesktopModules/KernRiver/Documents/ViewDocument.aspx?DocumentID=271 (Accessed April 2017).

Table 2. Take-Away Capacity at Gas Utility Receipt Points.

Gas Utility Receipt Point	**Maximum**	**Adjusted***
	(Bcfd)[6]	**(Bcfd)**
SoCalGas[7]		
California Line 85 Zone	0.16	0.060
California Coastal Zone	0.15	0
Wheeler Ridge Zone	0.77	0.77
Southern Zone	1.2	1.0
Northern Zone	1.6	1.6
SoCalGas Subtotal	3.9	3.4
PG&E		
Redwood Path (Line 400/401)	2.0	1.9
Baja Path (Line 300)	1.0	1.0
CA Production	0.039	0.039
PG&E Subtotal	3.1	2.9
Direct Delivery[8]		
Kern River/Mojave	1.2	1.2
TOTAL	8.1	7.5

7 Maximums reported for SoCalGas found in the 2016 California Gas Report, p. 82.

8 This should include the very small amount delivered via connection from Paiute Pipeline into Lake Tahoe.

Source: Compilation by Aspen Environmental Group

2016 California Gas Report, Wood, Natural Gas Infrastructure, 2009

** The adjusted figures are a better representation of the firm delivery capability than the maximums.*

All told, the take-away capacity of PG&E and SoCalGas, taking into account direct deliveries by Kern River within the state, is 7.5 Bcfd making the working capacity of the state's storage fields critical in meeting gas peak requirements of 11.8 Bcfd (see Conclusion 2.3). Any significant increase in take-away capacity would require building new pipelines in California.

This combination of multiple pipelines into the State coming from diverse supply basins[26] combined with the seasonal and hub services allowed by underground gas storage located near the load centers, make California different from any other natural gas market or system in the U.S. For example, California stands in stark contrast to the U.S. northeast which has historically relied on gas produced and transported from the Gulf Coast. The two pipelines that bring Canadian gas (Iroquois and Maritimes & Northeast) to the northeast are not connected to storage.[27] The closest analog to California's gas system might be Union Gas in Ontario, Canada, with its vast storage facilities near Windsor, but even Union Gas does not have the diversity of supply sources and pipeline options as California. Safety notwithstanding, California's access to underground gas storage near its load centers makes it the envy of the nation's natural gas market.

The Working Capacity of a Storage Field

The "working capacity" of a storage facility or inventory shown in Table 3 reflects the quantity that can be injected and withdrawn from the field.[28] California has 375 Bcf of working capacity to hold natural gas underground using 12 individual facilities. Working capacity calculations exclude what is known as "cushion gas" which is simply natural gas that is held in the field (not produced) and serves to maintain pressure in the reservoir to drive working gas out. Section 1.1 in Chapter 1 contains detailed information about each storage facility and its key characteristics.

26. Basins supplying California include Alberta's Western Canadian Sedimentary Basin, the Four Corners Area's San Juan basin, west Texas' Permian basin, the Rockies, and in years past even the Texas/Oklahoma Panhandle's Anadarko basin.

27. It takes three days for stored gas to go from far western New York or Pennsylvania to the northeast.

28. Under normal conditions operators do not withdraw cushion gas because the pressure decline associated with withdrawal can allow water to invade what was previously gas-filled pore space and consequently decrease gas storage capacity. Furthermore, the long residence time of cushion gas in the reservoir allows it to mix and entrain residual hydrocarbon components. Operators may have to process these components out of the gas in order to reach the pipeline quality required by utility tariffs. Both conditions can take time to correct in order to restore the reservoir to full working capacity.

Table 3. Underground Gas Storage Working Inventory Capacity.

	Working Capacity (Bcf)	**Maximum Withdrawal Capacity[9] (Bcfd)**
U.S.	4700	
California	370	
Utility-Owned & Controlled	240	5.9
PG&E	100	2.2
SoCalGas	140	3.7
Independently Owned	130	2.7

9 Maximum withdrawal capability is achievable at full field inventory. As inventory declines, so does deliverability. Decline is not linear but depends on field configuration, including number of wells. These values do not reflect the impact of DOGGR's new rules that allow withdrawal only through the inner tubing instead of tubing plus well casing. The value of the utility-owned facilities also includes 1.8 Bcf for Aliso Canyon.

Source: EIA, U.S. Field Level Storage Data CEC 2003 Natural Gas Market Assessment

1.0.3 General Natural Gas Demand Levels

The natural gas market in California represents about 8% of the nation's total, or on average close to 6 billion cubic feet (Bcf) per day. Only Texas consumes more natural gas than California. Energy Information Administration data indicates California's annual share of the nation's natural gas market has ranged as high as 10% over the last 20 years (EIA 2017 U.S. Total Natural Gas Consumption). In terms of per capita gas use, California's gas consumption ranks about 23rd (StateMaster.com, 2001).

Figure 5 shows the annual demand for the U.S. and California. The use of natural gas across the U.S. has increased in recent years mostly due to low natural gas prices and new or proposed environmental regulations causing electricity generators to move away from coal. Some of the demand increase did come from industrial demand for gas, with a small increase in residential and commercial demand. In contrast, California's use of gas has remained level partly because the State did not have much coal-fired electricity to begin with.

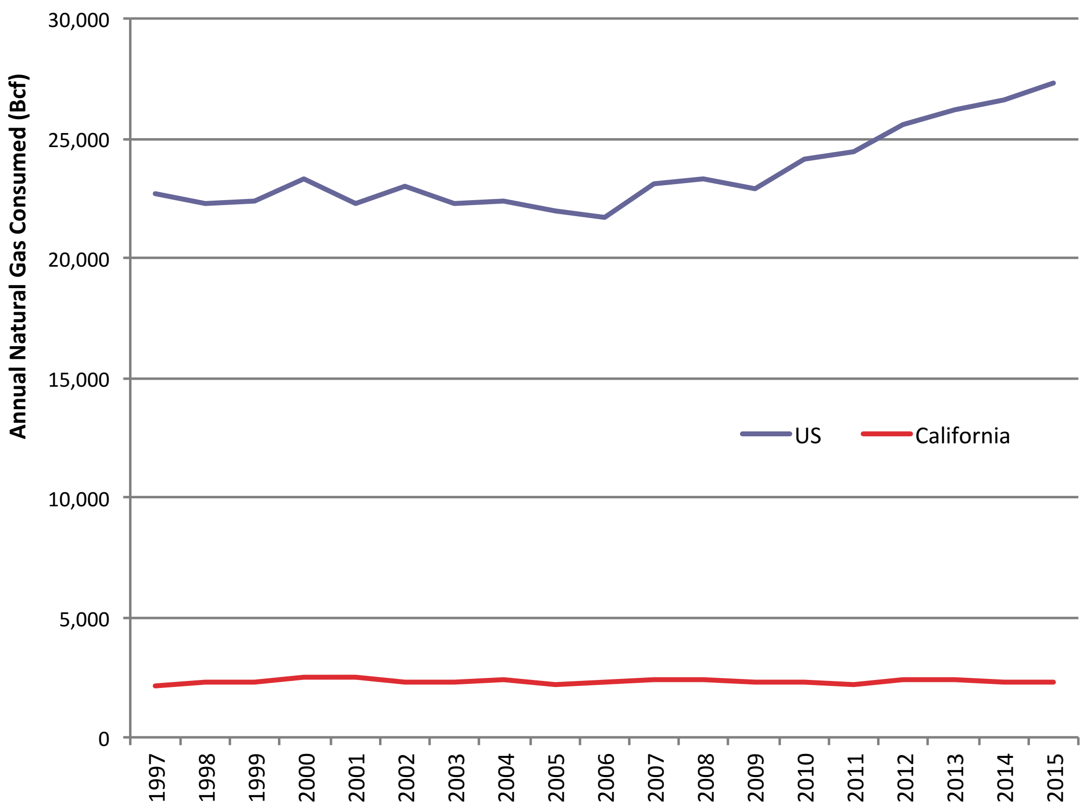

Figure 5. U.S. and California Annual Natural Gas Demand
Source: U.S. Energy Information Administration, Natural Gas Annual

Historical data illustrates how California's natural gas demand varies by month. As shown in Figure 6, California's demand for gas peaks in winter with higher use of natural gas for space heating in those cooler months. In some years, demand peaks in December and in other years it peaks in January. In most years, an intermediate, lower peak occurs in summer. This intermediate summer peak reflects use of gas by electric generators. The late summer fall-off in hydro-electric generation and higher temperatures resulting in a demand for air conditioning cause the summer peak. The drought conditions from 2010 to 2014 exacerbated the summer peaks, whereas somewhat milder summers and an increase in renewable generation in 2015 and 2016 resulted in smaller summer peaks. Weather explains most of the year-to-year variation, due both to changes in heating-degree days in winter and cooling-degree days in summer.

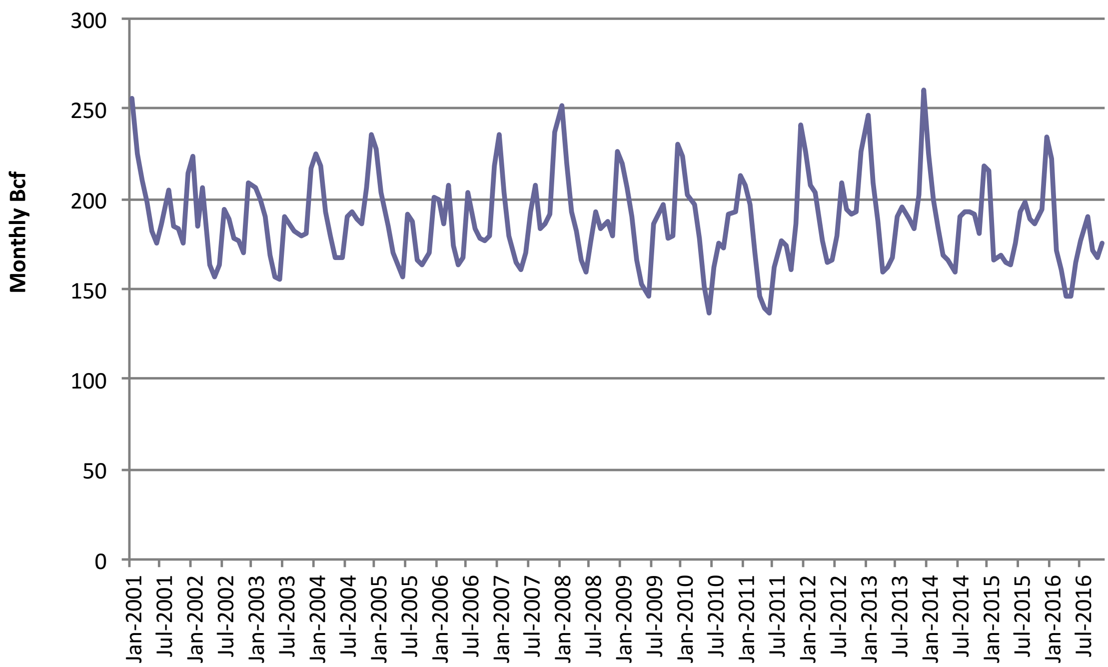

Figure 6. California Natural Gas Demand by Month: 2001–2016
Source: U.S. Energy Information Administration, Natural Gas Monthly

Figure 7 breaks monthly demand out, stacking it by customer class. Industrial and commercial class demands vary by month but are relatively flat in comparison to residential and electric generation (EG) demand. Figure 8 breaks this down further to focus on just core and EG total monthly demand. Individual days would show even more extreme peaks. The figure makes it easier to see the winter peak in core customer demand and the summer peak in EG. Note the low electric generation in spring 2011 caused by late spring precipitation, which increased the amount of hydropower available and forestalled use of natural gas until the hydro run-off had been used.

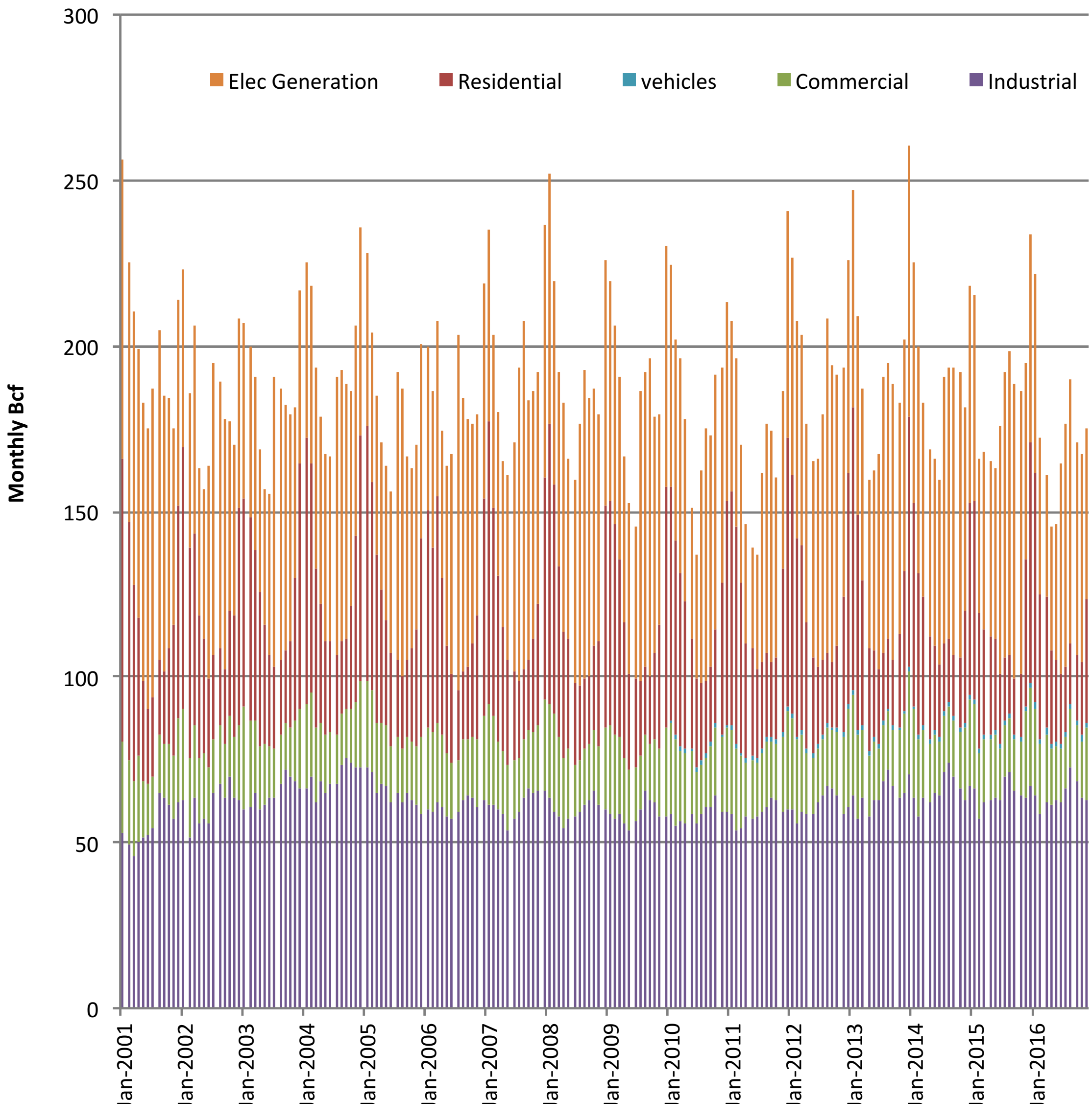

Figure 7. California Monthly Average Natural Gas Demand by Class
Source: U.S. Energy Information Administration, Natural Gas Monthly

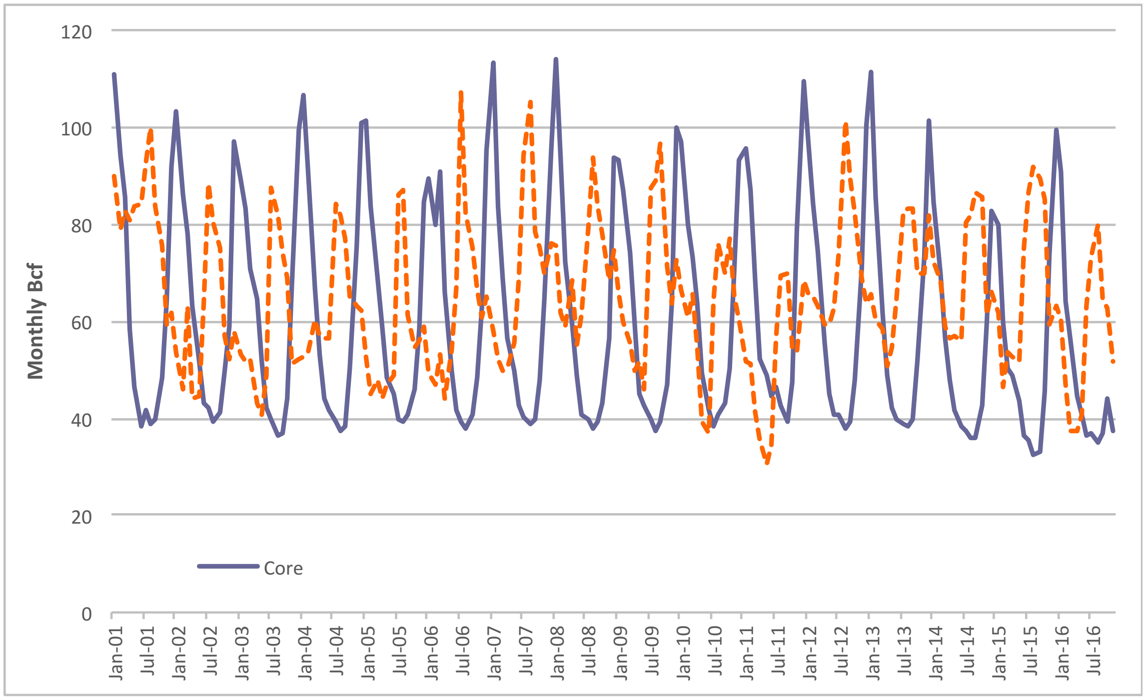

Figure 8. Core and EG Demand by Month
Source: Aspen Analysis of EIA Monthly Demand Data

1.0.3.1 Expectations for Future Gas Demand

The utilities predict that statewide total natural gas demand will decrease significantly in the next 15 years. Table 4 provides the latest publicly-available forecasts prepared by the utilities. These project average daily demand in both average (normal) and cold, dry-hydro years to decline by more than 0.7 Bcf per day by 2020. That would be an 11.5% decline from 2016's forecasted demand for an average temperature year. The decline by 2030 is double that (1.4 Bcf per day), representing a 23% drop relative to 2016. The utilities attribute the forecasted decline to "aggressive energy efficiency," meaning more efficient power plants and policies are anticipated to acquire and prefer zero- or low-carbon generation alternatives.

Table 4. Gas Utility Demand Forecasts.

	2016	**2020**	**2025**	**2030**	**Projected Decline from 2016 to 2030**
Condition	**(Bcfd)**				
Average Temperature and Normal Hydro	6.1	5.4	5.0	4.7	-1.4
Cold Year and Dry Hydro	6,774	5,978	5,853	5,363	-1,411

Source: 2016 California Gas Report

These demand forecasts may not capture all the factors that will affect overall gas demand. At a 2017 IEPR workshop, CEC Chair Weisenmiller noted that the retirements of California's San Onofre and Diablo Canyon nuclear units will cause an increase in forecasted gas demand (CEC, 2017a). The nuclear units are expected to be replaced by a mixture of resources with 50% or more to include energy efficiency and demand response, energy storage and renewables- in the case of San Onofre. [29] In a workshop one day prior to the 2017 IEPR workshop, CPUC staff cited 9,380 MW of gas-fired generating capacity expected to retire by 2022 (Kito, 2017). This figure excludes another 2,839 MW of gas generation owned by Los Angeles Department of Water and Power (LADWP) that must also retire due to the State Water Resources Control Board's (SWRCB) rule to eliminate once-through cooling (Los Angeles Department of Water, 2016). Retiring units are older, with higher heat rates than newer generation, meaning that they consume more natural gas in each hour they operate relative to newer units. Staff further cited the growth of Community Choice Aggregations (CCA), which promise consumers cheaper and greener renewable sources. This shift, ostensibly, would further reduce use of gas-fired generation and may not be captured by production cost dispatch projections that are used to project the gas-fired generation burn.

Utilities are finding that some gas-fired power plants are being dispatched (i.e., operate) too seldom to accrue sufficient operating revenue to be profitable.[30] Some generators have threatened to pull their equipment and move it out of California, a seemingly extreme and unlikely response, but it demonstrates the frustration among independent generators and suggests a confirmation of the reduction in natural gas demand for electric generation as California increasingly shifts to renewables. This change is also unlikely to be captured in the demand forecasts and is another indicator overall future California gas demand will decline.

Finding: While forecasts suggest falling total gas demand out through 2030, none of the forecasts break out how much gas might be necessary to firm intermittent renewable generation and the timing of that need, factors which can affect the need for gas storage.

29. See "Preliminary Reliability Plan for LA Basin and San Diego," August 2013. See also "Joint Proposal for the Orderly Replacement of Diablo Canyon Power Plant with Energy Efficiency and Renewables" (CPUC et al., 2013).

30. One example of this is Calpine's Sutter power plant. See http://www.powermag.com/calpine-to-take-uneconomic-ccgt-plant-offline-in-calif/ (Accessed May 2017).

1.1 What is the role of gas storage in California today?

Storage serves both physical balancing and financial roles in California today. The roles are listed in Table 5 and described in further detail below.

Table 5. Functions of Underground Gas Storage in California.

Function	Short Description
Physical balancing of supply and demand functions	
Monthly Winter Demand	Storage provides supply when monthly winter needs exceed the available pipeline capacity.
Flat Production	Storage sustains flat aggregate natural gas production.
Winter Peak Day Demand	Storage provides supply when winter peak day demands exceed pipeline capacity.
Intraday Balancing	Storage provides intraday balancing to support hourly changes in demand that the receipt point pipelines cannot accommodate. This service is essential in allowing the flexible use of gas-fired electricity generators to back up renewable generation.
Stockpile	Storage provides an in-state stockpile of supply in case of upstream pipeline outage or other emergency such as wildfires.
Financial functions	
Seasonal Price Arbitrage	Storage allows savings through seasonal price arbitrage (winter prices are usually, but not always higher than summer prices).
Liquidity/Short-term Arbitrage	Grants marketers a place to hold supply and take advantage of short-term prices for liquidity and short-term arbitrage.

Source: Aspen Environmental Group

1. Monthly Winter Demand

The first function of storage in meeting seasonal demand is easy to visualize. Once gas wells are completed and begin production, they produce at an ever-declining rate. New wells must be drilled to offset that decline. Consequently, natural gas production tends to be relatively flat over a year and flat over a day. Against this flat production, demand varies by season. In its simplest form, the difference between production and demand is injected into storage in the summer months and withdrawn from storage in the winter months. Using storage in this manner positively affects pipeline utilization rates by using pipeline capacity more efficiently and cost-effectively. Figure 9 illustrates this generic use of storage.

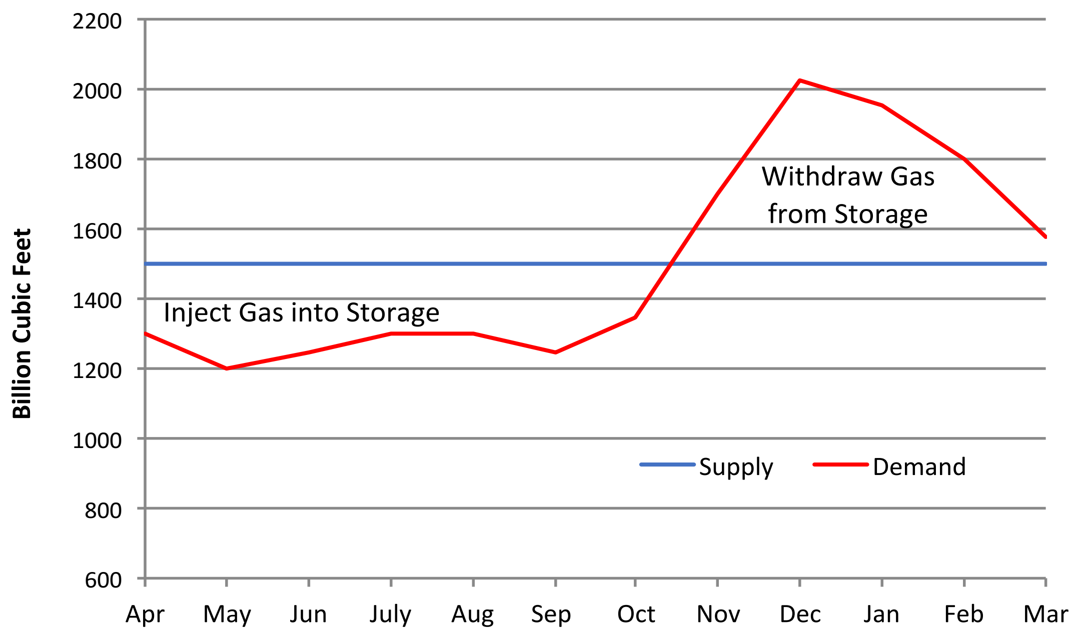

Figure 9. Stylized Illustration: Using Storage to Manage Variable Demand Against Flat Supply[31]
Source: Aspen Environmental Group

This stylized illustration depicts in conceptual terms the way California uses gas from underground storage to meet the portion of winter demand for which we chose not to build pipeline capacity.

A 1959 CPUC decision marks the conscious choice to use underground gas storage and approves PG&E's acquisition and conversion of the gas field at McDonald Island from natural gas production to underground gas storage:

> *To make such long-distance transmission projects economically feasible, it is necessary that the transmission pipeline be operated at as high a load factor as possible, resulting in a fairly constant flow of gas in large quantity at all times during the year. On the other hand, the gas requirements for applicant's system are subject to large seasonal, weekly and daily fluctuations. After engineering and economic studies, applicant has concluded that the most feasible way of attempting to equate these opposing requirements of supply and usage is to store gas in underground depleted or partially depleted gas fields during periods of low demand and to withdraw gas therefrom during system peak demands and other periods of large usage (CPUC Decision No. 58706 1959).*

31. Values selected for purposes of illustration; actual supply, demand and daily injection and withdrawal rates vary from these stylized monthly averages.

Building storage costs less than building pipeline capacity to meet peak demand because the incremental pipeline capacity to meet peak demand would only be used on a peak day. This would have resulted in paying for capacity that is only used once in a while.
In-state storage provides better economics than new pipeline capacity.

Figure 10 compares average daily demand for each month to California's total 7.5 Bcfd pipeline take-away capacity as determined in Table 2. This total pipeline take-away capacity would be the maximum daily demand that can be served without access to some sort of supplemental gas supply.

Finding: Nearly every winter has a month with average daily demand that exceeds, or nearly exceeds, pipeline take-away capacity.[32]

Conclusion 2.1: Without gas storage, California would be unable to consistently meet the winter demand for gas.

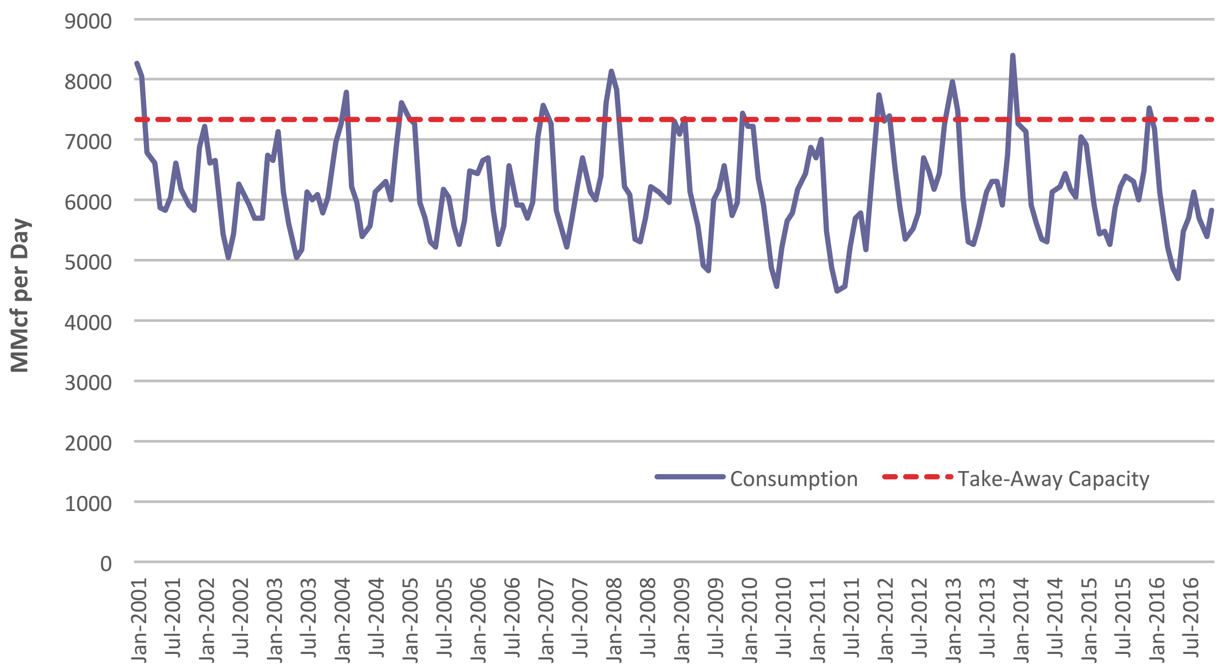

Figure 10. Average Daily Gas Consumption by Month Vs. Take-Away Capacity
Source: Aspen Environmental Group

32. Gas operators like to maintain a margin, or headroom, between what their system can do versus maximum demand. This accommodates unplanned outages as well as under-forecasts of maximum demand.

2. Sustaining flat aggregate wellhead production

Gas production rates also limit the rate of gas imports to California. Gas producers who serve California do not have to modify production patterns to follow load and would object to such a requirement.

Conclusion 2.2: If California had no gas storage, the burden of allowing relatively constant gas production to match to seasonally varying demand would shift to production and storage located more than 1,000 miles upstream from California.

No study has been found that contemplates such a scenario.

3. Winter Peak Day Demand

Gas storage bridges the gap between average daily consumption in winter months and the swing up to peak day demand, sometimes called a "needle peak." A 2001 report by the California Assembly's Subcommittee on Natural Gas Costs and Availability found, "[t]he natural gas pipeline system is not able to supply enough natural gas to meet peak system requirements. Therefore, stored natural gas must be withdrawn to supplement the pipeline supplies to avoid service interruption" (Canciamilla, 2001). At that time, historical winter peak demand was 5,300 MMcfd relative to SoCalGas' pipeline deliverability of 3,500 MMcfd.

The utilities in the California Gas Report (CGR), describe their highest winter and summer sendouts for each of the last five years.[33] These are shown in Table 6. The highest recorded total demand in the recent five-year period is 11,157 MMcfd. This occurred on December 9, 2013. The second-highest was 9,423 MMcfd, occurring on December 19, 2012. Meeting these levels of demand without using underground gas storage (and all else equal) would require building 4,000 MMcfd of new pipeline capacity and associated compressor stations and equipment.

Data presented in the CGR demonstrates times that California's intrastate pipeline take-away capacity is inadequate to meet summer peak day needs. The highest summer day sendout recorded by the utilities (including deliveries to customers directly served by Kern River) in the last five years was 7,801 MMcf per day. This occurred on August 13, 2012. 2015's September 10 was not far behind, at 7,795 MMcf per day. California's 7,511 MMcfd total pipeline take-away capacity is insufficient to serve that level of demand.

33. Daily data can also be pulled from PG&E and SoCalGas' public web sites, long known as "bulletin boards" in the industry, which exist for the purpose of providing gas market participants with information to increase market transparency. No known source collects daily utility demand data independent of the gas utilities. This makes sense, as the utilities are the only entity that can measure system sendout and therefore would be the ultimate source of such data.

Good planning requires forecasting peaks, not just using recent recorded peaks. California's utilities plan to a forecast because they cannot know exactly what weather conditions will occur in any given year. If the utilities plan only to meet recent peaks, they run the risk that more extreme conditions will occur and we will not have adequate capacity to serve demand under those more extreme conditions. Looking only at the recent past ignores this critical statistical information. The CGR contains the gas utilities' forecasts of demand by year to 2022 and then every five years out to 2035. For 2020, PG&E and SoCalGas together show 9,068 MMcfd for a winter peak day sendout which is more than can be served with the intrastate take-away capacity of 7,500 MMcfd (7.5 Bcfd). For summer in 2020 they forecast 5,265 MMcfd peak day sendout. Adding in the load served directly by Kern River results in a summer peak forecast of 6,446 MMcfd which appears servable with current intrastate take-away capacity.

For winter, we show two figures: they differ with respect to the relative level of severity assumed to drive core customer loads. SoCalGas' peak day reflects core customer load resulting from a 1-in-35 year cold experience, meaning that the forecast reflects the highest number of heating degree days expected to occur once every 35 years.[34] This 1-in-35 year occurrence is the design standard to which SoCalGas' local transmission and distribution system is built, to which the CPUC has assented on numerous occasions. Both of the winter forecasts in Table 6 use the 1-in-35 condition to calculate core load for SoCalGas.

For PG&E, Table 6 shows the two different forecasts used for planning and cost allocation: a 1-in-10 (for both core and non-core) and the 1-in-90 that captures higher core load. The difference between the two demand conditions for PG&E's core load is about 7 degrees Fahrenheit in the system composite temperature (calculated at six weather sites) which increases core demand by approximately 570 MMcfd. For non-core customers, the load forecast is always calculated using the less extreme 1-in-10 weather condition.

Because the size of the intrastate pipelines limits California's ability to import gas, 4,334 MMcfd of peak daily demand cannot be met (Table 6). Recall Table 1 showing that interstate pipeline capacity to California of 10.6 Bcfd and Table 2's derivation of an adjusted take-away capacity equal to 7.5 Bcfd. Even if the interstates were full to the California state line (and the odds of that happening on a peak day are probably low), California has no way to get that gas from the state line to the state's gas consumers. Interstate pipeline capacity cannot meet the more extreme winter peak that includes the 1-in-90 demand criterion for PG&E.

34. A heating degree day is the difference in degrees Fahrenheit between the actual temperature experienced and a benchmark temperature of 65 degrees.

Table 6. State-wide Peak Day Demand Deficit Relative to Intrastate Pipeline Take-Away Capacity.

Date	**Pipeline Capacity**	**Demand =**	**Deficit**
	(Bcfd)		
Recorded			
August 13, 2012	7.5	7.8	-0.3
September 10, 2015	7.5	7.8	-0.3
December 9, 2013	7.5	11.1[10]	-3.6
December 19, 2012	7.5	9.4	-1.9
Forecast			
Cold Temperature Dry Hydro Year (Average Day)	7.5	6.0	surplus
Total Winter Peak Day 2020: • PG&E 1-in-10 for core and non-core • SoCalGas 1-in-10 for non-core and 1-in-35 for core • Direct serve load	7.5	10.2	-2.7
Total Winter Peak Day 2020: • PG&E 1-in-90 core and 1-in-10 for non-core • SoCalGas 1-in-35 for core and 1-in-10 for non-core • Direct serve load	7.5	11.8	-4.3
Summer 1-in-10 Peak Day 2020 + Direct Serve	7.5	6.4	surplus

10 Of this, 4,836 MMcfd occurred on the PG&E system (see Pipe Ranger archives for date) and 5,011 MMcfd on SoCalGas (see Envoy archives for date). This leaves 1,310 MMcfd of direct-served load to reach the 11,157 statewide total shown.

Source: Aspen Environmental Group. Sendout taken from 2016 California Gas Report.[35]

Table 7 breaks the forecasted deficit out between PG&E and SoCalGas. PG&E appears to have a larger deficit in winter than SoCalGas when looking at its more extreme 1-in-90 peak day. By 2020, both distributors appear to have surpluses available to meet summer 1-in-10 peak day demand.

35. Demand on the reported dates from 2016 CGR, p. 53: "Statewide Recorded Highest Sendout." Peak day demands for SoCalGas are 1-in-35-year occurrence from p. 93. The 1-in-10 for PG&E comes from p. 53 and the 1-in-90 comes from p. 52. The Direct Serve load of 1,181 MMcfd comes from p. 21's "Statewide Annual Cold Temperature/Dry Hydro Requirements" table. The direct serve load is largely for EOR cogen so logically it should not vary with temperature.

Table 7. Forecast Peak Day Capacity Deficit Breakdown: PG&E versus SoCalGas (does not include the direct serve component included in Table 6).

	PG&E				**SoCalGas**			**Total Utility**
	Pipeline Capacity	Demand	Deficit		Pipeline Capacity	Demand	Deficit	Total Deficit
	(Bcfd)							
Winter Peak Day 2020 • PG&E 1-in-10 for core and non-core • SoCalGas 1-in-10 for non-core and 1-in-35 for core	2.9	4.1	-1.2		3.4	5.0	-1.5	-2.7
Winter Peak Day 2020 • PG&E 1-in-90 core and 1-in-10 for non-core • SoCalGas 1-in-35 for core and 1-in-10 for non-core	2.9	5.7	-2.8		3.4	5.0	-1.5	-4.3
Summer 1-in-10 Peak Day 2020	2.9	2.2	0.7		3.4	3.0[11]	0.4	-1.1

11 SoCalGas' forecasted 1-in-10 summer peak demand for 2017 is higher, at 3,300 MMcfd, which results in a deficit of 115 MMcfd that must be made up with gas from storage. This is separate from the use of storage to meet the intraday balancing needs of electric generators.

Source: Aspen Environmental Group. Demand taken from 2016 California Gas Report.

*** The SoCalGas forecast in this case is 1-in-10 for non-core and 1-in-35 for core; PG&E is 1-in-90 for core and 1-in-10 for non-core.*

Finding: California does not have enough intrastate pipeline take-away capacity to meet forecasted peak winter demand. California's intrastate pipeline capacity (7.5 Bcfd) is insufficient to meet the forecasted 11.8 Bcfd peak load corresponding to a very cold winter day.

Conclusion 2.3: California does not have enough intrastate pipeline take-away capacity to meet forecasted peak winter demand. Currently, winter peak load of 11.8 Bcfd can only be met reliably if storage can deliver 4.3 Bcfd.

Finding: The California utilities, together, have enough storage delivery capacity to meet winter peak day demand based on historic regulatory and operational requirements with about 0.5 Bcfd surplus that can be utilized in case of gas system outages.[36]

36. This reliability estimate does not include independent storage of 2.7 Bcfd because independent storage has no obligation to serve.

This simple comparison of capacity versus demand is useful for understanding why storage is important to reliability. However much more analysis is required for detailed utility system planning. That planning must be done with hydraulic models that capture constraints that may exist within a gas system and can assess the transient dynamic changes in demand versus supply during the gas day. Hydraulic modeling takes into account the flow rates of gas given the pressure distribution in the pipeline network and frictional resistance. These factors control whether enough gas can be supplied at a specific location. In other words, the balances shown delimit the best-case outcome at the assumptions shown and a hydraulic analysis may well find impacts that could be worse.[37] Even when the analysis shows an aggregate surplus of pipeline capacity versus peak day demand it does not necessarily mean storage is not needed. It may still be needed in certain hours of that day.[38]

4. Daily and hourly balancing

Daily and hourly balancing is a critical short-term function of gas storage. Both PG&E and SoCalGas allow their customers a tolerance on the requirement to match scheduled deliveries with scheduled usage. That tolerance is 10% of total usage in a month, and the customer has until the end of the following month to settle their imbalance account with the utility. In the case of under delivery of gas supply, once line pack[39] is depleted (a decision made at the sole discretion of gas operators) the utility uses gas from storage to remedy

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37. Unlike the electricity system where stakeholders can sign non-disclosure agreements to obtain the dataset and run system flow models, the gas utilities have as yet never provided their datasets to third parties and have repeatedly insisted that their systems are too complicated for anyone else to model. Results of a 2014 system expansion study for SoCalGas and SDG&E can be found at https://beea.socalgas.com/regulatory/documents/2014-gas-system-expansion-study.pdf and a 2011 storage capacity study at https://socalgas.com/regulatory/documents/StorageExpansionStudy2011.pdf. Both accessed July 2017. Both studies were prepared pursuant to CPUC Decision No. 07-12-019 and were reviewed by global engineering consultancy GL Nobel Denton, which is also the vendor of the hydraulic modeling platform used by both PG&E and SoCalGas and well-known in the industry.

38. The reliability assessment presented at the May 22, 2017 Energy Commission's Joint Agency workshop on Aliso Canyon reliability shows the importance of hydraulic analysis. SoCalGas' summer high sendout day forecast for 2017 in the CGR is 3,301 MMcfd, implying a surplus in summer 2017 of 124 MMcfd. The hydraulic analysis shows SoCalGas must withdraw gas from storage to meet summer peak day demand. That hydraulic analysis, reviewed by outside experts including Los Alamos National Laboratory (LANL), demonstrated that in some hours, the needed withdrawal would reach close to the full hourly withdrawal capability of the three non-Aliso gas storage fields. This summer use of gas storage by SoCalGas has been known to gas suppliers and key stakeholders for years (see Figure 15 showing the monthly withdrawal pattern). All of the presentations from that workshop are available at http://www.energy.ca.gov/2017_energypolicy/documents/2017-05-22_workshop/2017-05-22_presentations.php (Accessed October 2017).

39. Line pack is gas that is maintained in a transmission pipeline or distribution main to keep it pressurized enough that customers can take gas out of it without pressures dropping so low that gas stops flowing. Line pack will be discussed further in the subsection discussing potential alternatives to underground gas storage.

the mismatch between receipts of gas into its system with demand from customers. This is particularly important for SoCalGas because when imbalances outstrip supply enough that system operating pressures fall below acceptable levels, they must either pull from storage or curtail load. These gas imbalance provisions remain among the most liberal in the industry.[40]

This balancing issue can be seen in the summer 2016 Aliso Canyon Risk Assessment Technical Report for hydraulic simulation of September 9, 2015 (shown below as Figures 11 and 12).[41] This simulation demonstrates what would happen without gas from storage. In the simulation, SoCalGas saw load growth all day, starting at the hourly equivalent of 2,800 MMcfd and increasing over the afternoon to 4,500 MMcfd, while supplies coming in (i.e., receipts of gas) stood fixed at 3,500 MMcfd. By 11am, demand in the simulation outstrips supply by enough to cause pressures to begin to fall. They fall continuously on the northern system from about 10am until 10pm. Pressures within the LA Basin at Los Alamitos and El Segundo (with power plant and refinery load located nearby) are in decline virtually at the start of the gas day, at 400 psig at 6am and drop continuously until 7pm, roughly an hour after load begins to fall at 6pm. The analysis did not indicate what explicit minimum operating pressures would require curtailments absent gas from storage, but stated that the decline from 400 psig down to 325 psig caused by the supply-demand imbalance would likely have resulted in load curtailments absent the ability to pull gas from all four SoCalGas storage fields.[42]

Finding: Average daily scheduling of gas delivery generally works because the gas company covers the hourly mismatch between flat deliveries and variable usage. Electric generation load causes the change in gas load shown in Figure 11 in hours 12 through 7. Since electric generators have to schedule the same quantity of gas delivery each hour, the incremental supply often comes from storage.

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40. Baltimore Gas and Electric (BGE) recently updated its balancing provisions using customer smart meter data. It had been allowing suppliers until the following summer to make up differences, which would be more liberal than California's. BGE has much lower gas demand than California and owns some storage. See McShane, "Leveraging Gas Smart Meter Technology to Improve Energy Choice" June 2017.

41. Hydraulic modeling allows simulation of physical pipeline operations. It calculates operating pressures over the course of a gas day and identifies conditions where low or high-pressure limits, among other parameters, are violated. Hydraulic modeling is routinely used to assess system capability to serve new load and the impact of adding new facilities.

42. While the demand analyzed came from September 9, 2015, the supply available assumed limited pipeline flowing supply of only 1,878 MMcfd, with the rest of the gas supply coming from storage. Pulling that 1,589 MMcfd from SoCal's other three fields (Honor Rancho, La Goleta, and Playa del Rey) essentially used them at their maximum withdrawal capacities. Operating records posted on Envoy show that supply on September 9 consisted of 2,495,000 Dth and a storage withdrawal of 1,126,000 Dth (using the units displayed in Envoy). Customers were out of balance that day by 347,000 Dth. The point here is merely to demonstrate the need for gas from storage to balance the system within the gas day.

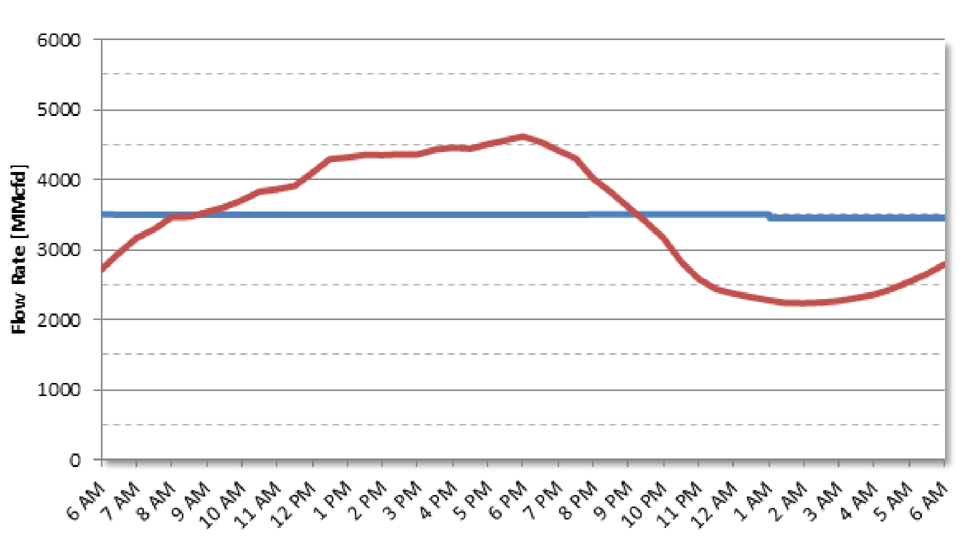

Figure 11. Supply Receipts and Load by Hour for SoCalGas September 9, 2015
Source: Aliso Canyon 2016 Summer Technical Assessment

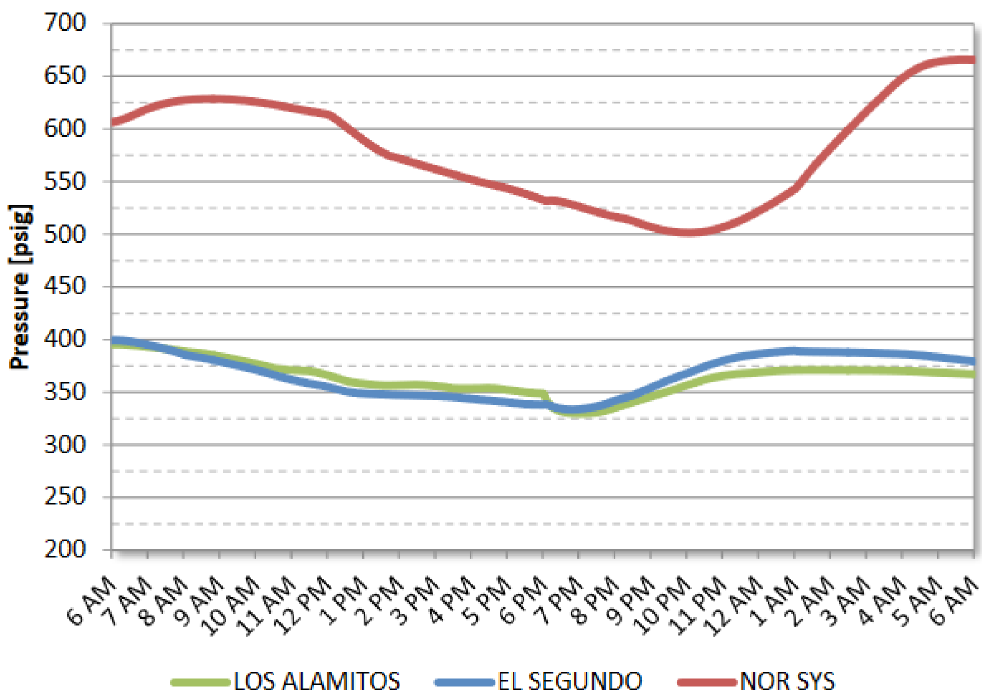

Figure 12. Hourly Operating Pressures on SoCalGas September 9, 2015
Source: Aliso Canyon 2016 Summer Technical Assessment

PG&E and SoCalGas reserve some of their storage capability explicitly for balancing. PG&E reserves 75 MMcfd of injection and withdrawal, and up to 4 Bcf of inventory capacity to balance its system (PG&E Pipe Ranger, 2017). SoCalGas reserves 8.0 Bcf of storage inventory capacity, 200 MMcfd of storage injection capacity, and 525 MMcfd of storage withdrawal capacity to balance its system.[43]

Conclusion 2.4: Gas storage provides crucial hourly balancing for the gas system in all seasons. Without gas storage, California would be unable to accommodate the electricity generation ramping that now occurs nearly every day and that may increase as more renewables are added to the grid.

Pipelines and utilities without storage have to impose much more onerous, restrictive conditions on customer imbalances. Kern River is an example of a pipeline that serves load in California, yet today has no storage located along its route. It has such tight balancing provisions that in 2001, when California's Department of Water Resources (DWR) was buying gas to supply a power project served by Kern River (in place of bankrupt PG&E and near-bankrupt Southern California Edison), the supplier required DWR to take the same quantity of gas every day, even on weekends when the project was not likely to operate. DWR had to find a buyer for the gas on weekends on grounds that there was no place on the Kern River system to put the gas. A sale on a weekend when demand is typically lower than on a weekday required selling the gas for less than the purchase price, i.e., at a loss, thereby increasing costs to California consumers. (Differences between weekend and weekday market prices vary depending on market conditions. In that timeframe, those differences might have been as much as 20% of the daily price.) In general, these tight balancing provisions are evidenced in frequent warnings to shippers that the system is close to its over-packed or over-drawn limits, and admonishments to keep their deliveries matched with their usage or pay penalties. Any flexibility that a pipeline offers is limited by its line pack or access to storage, and, except in California, tariffs that offer more flexible provisions command premium prices.

Electric generators face obstacles to paying premium prices for flexible services or to buying storage service in general. Storage is priced on a reservation charge basis plus a per unit cost to inject and withdraw. The cents per MMBtu added to the cost of natural gas cannot be

43. Approved in CPUC Decision No. 16-06-039, which adopted these values in a settlement in SoCalGas' Triennial Cost Allocation Proceeding (CPUC, 2014c). The balancing provision can be found at pages A-3 and A-4 of the settlement, which was filed via motion to the CPUC on August 31, 2015 and is available at http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M154/K297/154297787.PDF (Accessed April 2017). Interestingly, the TCAP settlement further provides that once the Aliso Canyon Turbine Replacement Project goes into service, the balancing function will be allocated an additional 145 MMcfd of storage injection capacity, for a total of 345 MMcfd, and some associated changes to the conditions required to call a High Pressure operational flow order (OFO) will occur. The change to the quantity reserved once the new compressors go into service and associated OFO rule change further demonstrate how closely storage and the balancing rules are intertwined.

recovered by generators bidding into competitively dispatched markets.
The independent merchant generators also prefer to purchase daily spot market gas whose price is likely to be aligned more closely with that of other bidders into electricity markets, and which helps set the market-clearing price in electricity market dispatch auctions. They see no increase in revenue from incurring the extra cost for holding storage. In California, it is easier to let the gas utility balance the system. These generators also have no obligation to operate if they do not have fuel. In contrast, gas-fired generators owned by vertically-integrated utilities (all located outside California since the divestiture required by AB 1890) tend more frequently to buy storage or flexible services because their regulator will allow them to pass that cost on in rates.

5. Stockpile

Storage protects California with a reserve, or stockpile, should one of the interstate pipelines fail or should weather to our east cause a reduction in gas supply available through the pipelines. This amplifies the problem of winter peak demand because unusually cold weather in the production basins can lead to wellhead and gathering line freeze-offs, shutting down production and consequently limiting gas supply available to California from the interstate pipelines. These same unusually cold events concurrently create much higher gas demand in states to our east, which further reduce gas available to California from the interstate pipelines. FERC and NERC staff, in their 2011 cold weather event report, documented seven cold weather events that resulted in curtailing more than 100,000 gas customers in Texas, New Mexico, Arizona, and San Diego.[44] They cite a 1989 event severe enough that PG&E notified CPUC commissioners it was preparing to curtail non-core customers.[45] In the 2011 event, temperatures in the Dallas area (likely somewhat warmer than in the heart of the Permian and San Juan basins that help supply California) dropped to -1o F. Farmington, NM in the heart of the San Juan basin, saw highs of 13 and 19 degrees, respectively, on February 3 and 4, and had four consecutive nights between 6 and -6 degrees (New Mexico State University Agricultural Science Center Farmington, 2011). The electric utility in El Paso, Texas reported 60 hours with temperatures below 18 degrees and lows near zero (El Paso Electric Company, 2011). The Permian basin reportedly lost 30% of its production and the San Juan basin lost between 50 and 70%. Forty percent of processing capacity across five supply basins including East Texas and the Gulf Coast was lost (Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1- 5, 2011). In the end, PG&E's stored gas was sufficient to address both the increase in load in its service area and the drop in supply flowing in from the El Paso system. Even with gas from

44. See "Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011," pp. 169 to 189. P. 3 of the "Legislative and Regulatory Responses by States" appendix documents that some of the 30,000 customers in New Mexico were without natural gas service for a week. The report also documents cold weather events affecting supplies in 1983, 1989, 2003, 2006, 2008, and 2010.

45. Opinion provided by technical expert..

storage, the drop in interstate deliveries to California was enough that SoCalGas curtailed service to 59 non-core (including electric generation) customers. San Diego Gas and Electric (SDG&E), which is served solely via SolCalGas' southern main line and is not connected to in-state gas storage, had to curtail all non-core load except for two generators that CAISO said were needed for grid reliability (Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1- 5, 2011).

Finding: Underground gas storage protects California from outages caused by extreme events, notably extreme cold weather that can drastically reduce out-of-state supplies.

Conclusion 2.5: Gas storage could increasingly be called on to provide gas and electric reliability during emergencies caused by extreme weather and wildfires in and beyond California. Both extreme weather and wildfire conditions are expected to increase with climate change. These emergencies can threaten supply when demand simultaneously increases.

6. Seasonal Price Arbitrage

Storage can serve a price function. To the extent that gas can be injected when gas market prices are low and withdrawn when prices are high, storage becomes a physical hedge against those higher prices (for price arbitrage). "Slow-turn" storage, i.e. that which can cycle once per year, is good for this type of summer versus winter price arbitrage. The turn rate is a function of how fast a field can be refilled and is determined by the magnitude of injection capability relative to the inventory. [46] As will be shown later, summer prices are not always lower than winter prices, so in some years the arbitrage result is negative. Fast-turn storage that allows several cycles per year is useful for shorter-term arbitrage. Natural gas marketers and producers tend to prefer short-term, opportunistic arbitrage in which they either store excess gas hoping for a higher-priced day on which to sell it, or use it to manage unforeseen changes in their production and sales portfolios.

Before the advent of competitive supply markets, utility storage did not serve price arbitrage. During this time, California's gas utilities invested in underground gas storage and natural gas was purchased by a utility from a pipeline under long-term contracts at a fixed annual price with fixed escalators. As such, seasonal price savings did not exist and price was not part of the justification for storage. Since then, we have seen periods of relatively stable prices, in which case, storage used for price arbitrage would have very little effect on natural gas prices to California consumers.

The natural gas spot market emerged after the 1970's gas shortage became the 1980's gas glut. FERC opened natural gas markets to commodity competition, allowing prices to be set

46. Until companies independent of the utilities began to invest in and offer storage services, most storage was single turn and took all summer long to refill a field before winter.

in the open market. This replaced long-term contracts that had linked natural gas prices to oil prices and escalated at fixed rates and contained provisions that required a utility to pay for the gas whether it took it or not. In so doing, FERC also directed that pipelines could no longer sell natural gas and required they provide transportation service on a non-discriminatory, open access basis (see FERC Order Nos. 380, 436, 500, and 636). As a result, the price for gas supply (often called the ‘commodity price’) began to be set on a monthly basis. One feature of this competitive market is that higher winter demand often results in winter prices being higher than summer prices. To the extent that a utility can buy extra gas at low summer prices and store it for winter, it can reduce its winter month gas purchases and thereby reduce costs to its supply customers.

Figure 13 displays so-called “citygate” prices for California as reported by EIA back to January 1989.[47] The data shows various price spikes, including several severe ones; some of which occurred during winter months. (The 2001 price spike is associated with the power crisis and a pipeline outage; the 2006 spike is due to hurricanes Katrina and Rita; and the 2008 spike is the commodity price run-up prior to the financial crisis.) All else equal, being able to pull lower-priced gas from storage in those months would have had the effect of reducing costs to Californians. Table 8 compares average summer and winter prices for the last five years. In 2012, 2013, and 2016, summer prices were lower than in the following winter and storage provided a hedge against higher winter prices. However, 2014 and 2015 show the opposite; winter prices fell and the achieved result from the storage hedge was negative. Assuming 82 Bcf of storage for core customers, the average net result for the five-year period would be a gain for those consumers of approximately $5 million.

47. Nominally, a citygate is the meter station where gas from an interstate pipeline is transferred to a local distribution company. On the PG&E system, the citygate is instead a series of virtual locations where gas transfers from its backbone transmission system into its local transmission and distribution system. A similar but not completely analogous concept applies on the SoCalGas system. One should interpret the prices shown as a proxy rather than as a literal price one can observe in the market.

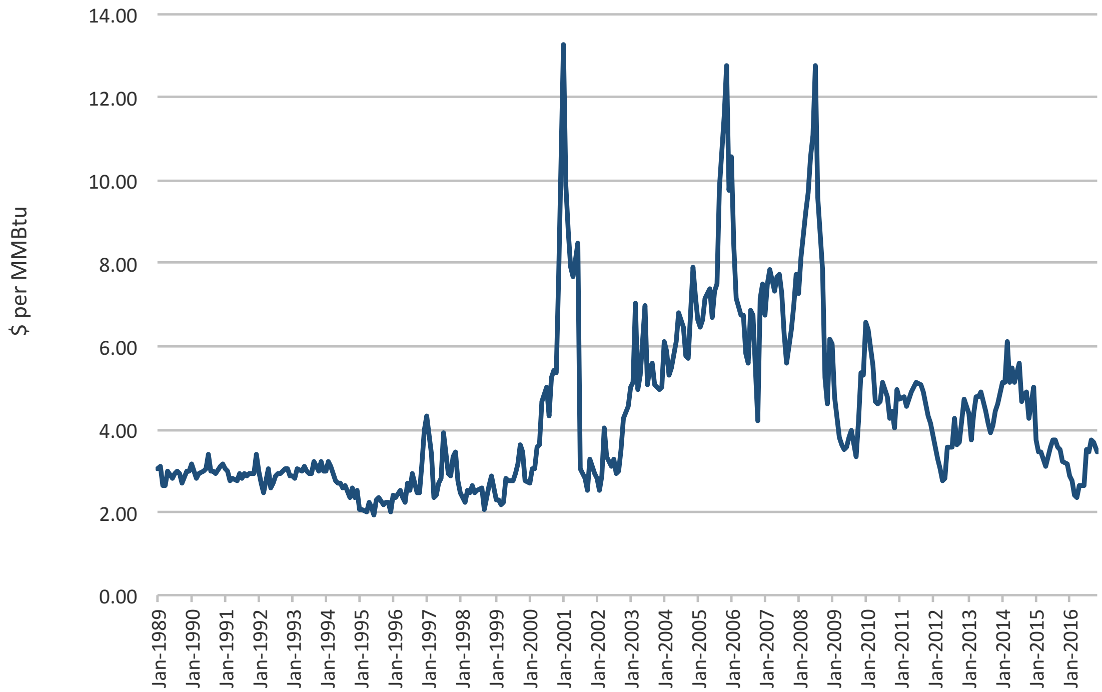

Figure 13: California "Citygate" Natural Gas Price by Month
Source: U.S. Energy Information Administration, Natural Gas Monthly

Table 8: Theoretical Physical Storage Price Hedge Results 2012 - 2017.

	Avg Price	**W-S Diff**	**Storage Reserved For Core Customers**		**Theoretical Seasonal**
	$ per MMBtu	**$ per MMBtu**	**Bcf**	**MMBtu**	**Savings to Core Customers $ (nominal)**
Summer 2012	3.48				
Winter 2012 - 13	4.29	0.81	82	86,100,000	$70,000,000
Summer 2013	4.43				
Winter 2013 - 14	5.10	0.66	82	86,100,000	$58,000,000
Summer 2014	5.11				
Winter 2014 - 15	3.98	-1.13	82	86,100,000	-$96,0000,000
Summer 2015	3.50				
Winter 2015 - 16	2.89	-0.61	82	86,100,000	-$53,000000
Summer 2016	3.14				
Winter 2016 - 17	3.69	0.55	82	86,100,000	$47,000,000
Total Seasonal Savings Since 2012					$25,0000,000
Average Seasonal Savings Since 2012					$5,000,000

Source: Aspen Environmental Group

Practitioners know that forecasting monthly natural gas prices is exceedingly difficult. Many focus instead on watching the strip of monthly prices traded on the New York Mercantile Exchange (NYMEX). These prices represent the price traders are willing to pay today for gas delivered in future months. Twelve calendar months of futures prices is known as the "12-month strip," and almost always displays the market's default expectation that winter prices will be higher than summer prices. The 12-month strip for April 13, 2017 appears in Figure 14 and displays an underlying expectation that next winter's prices will be perhaps twenty-five or thirty cents per MMBtu higher than those for summer 2018.[48]

Gas storage levels can also affect gas prices. EIA, since about 1998 (and the American Gas Association before that), collects data from storage facility owners on how much gas was injected or withdrawn during the prior week and releases this data every Thursday.[49] Sometimes, when forward prices display little seasonal variation, the trade press will report that storage injections are low for a given week and say the reason is because prices are not providing a reason to inject. However, such logic ignores the fact that storage is needed to match the physical seasonal difference between natural gas production and demand. Many utilities – not just in California – need stored gas to meet winter demand, regardless of winter versus summer price signals.

Conclusion 2.6: Seasonal price arbitrage can be considered a second-order benefit of utility-owned gas storage. In theory, the utilities could purchase financial contracts to achieve this price benefit. As long as California needs storage to meet winter reliability needs, however, it is prudent to also capture price benefits when they are available. This allows California to avoid the transaction costs that would be associated with using financial contracts to hedge winter prices.

48. The futures prices change every day based on news about supply and demand. It is entirely possible that the curve in July or September will look very different than this relatively flat curve of traded prices in mid-April.

49. Nationwide, the market often hangs in wait for the weekly report release and prices will noticeably change when reported activity deviates from normal weather, leading to larger- or smaller-than normal storage activity.

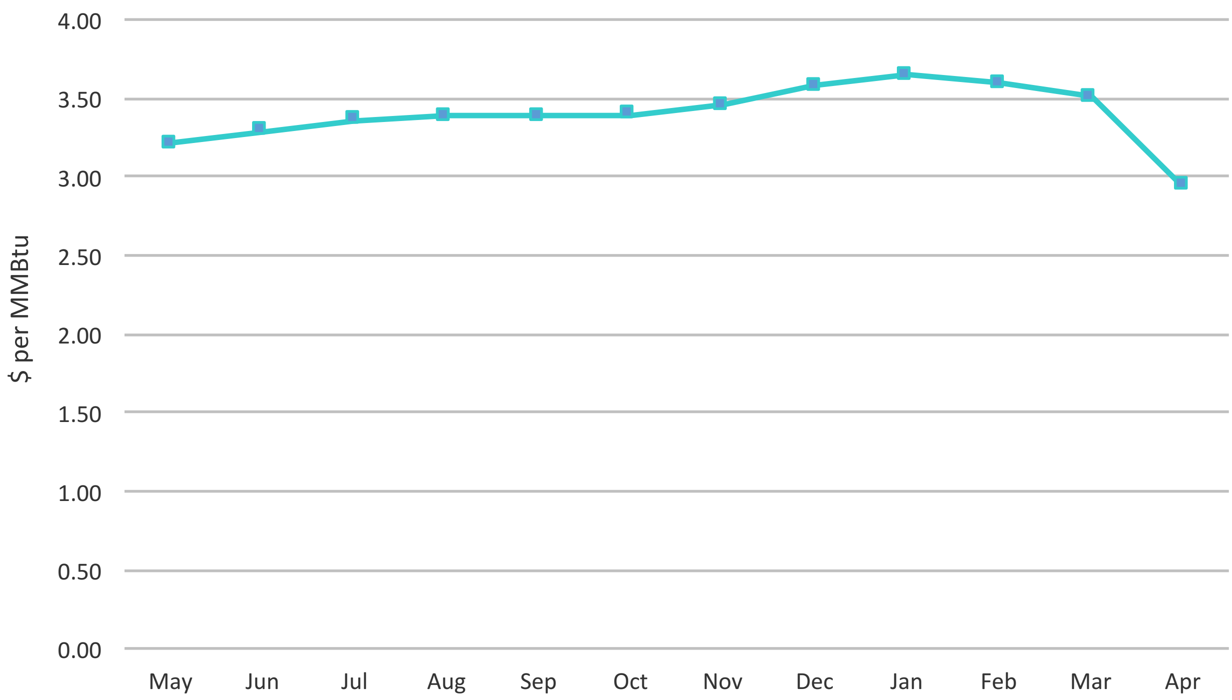

Figure 14. 12-month Futures Strip of Natural Gas Prices on April 13, 2017
Source: Aspen Environmental Group; prices via http://quotes.ino.com/exchanges/contracts.html?r=NYMEX_NG

7. Market Liquidity

Finding: Natural gas storage in California also enhances market liquidity. It allows marketers a place to store gas for short periods of time (in contrast to the utilities storing gas primarily for winter). This extra degree of freedom helps to manage dis-synchronies between sales contract starts and stops; the timing of new production coming on line; or maintenance periods at a production, gathering or pipeline facility.

Conclusion 2.7: Storage allows access to gas supply in local markets rather than having to wait for it to be transported. In short, storage provides more options to dispose of or to access supply.

Underground gas storage helps the State meet the winter demand for gas and provides a vehicle for intraday balancing of supply and demand, which has become of critical value as intermittent renewable electricity generation has become more important. Storage also creates a way to stockpile supplies inside the State should interstate pipelines fail or should weather to the east of the State cause interruptions in either natural gas production or higher demand. Storage allows physical price arbitrage by storing gas when prices are low to use later when prices are high. Storage also gives buyers and sellers an extra “sink” or “source” to make the market more fluid.

Conclusion 2.8: The overarching reason for the utilities' underground gas storage is to meet the winter demand for gas. If storage capacity is sufficient to help meet winter demand, it is then able to perform all the other named functions, including intraday balancing, compensating for production which is not aligned with demand, creating an in-state stockpile for emergencies, and allowing arbitrage and market liquidity.

Recommendation 2.1: In evaluating alternatives that would reduce dependence on underground gas storage and shift norms about controlling interruptibility, the State should obtain a detailed analysis of the gas system to ensure that the balancing roles gas storage plays on all timescales can be effectively managed by other means. This analysis should include hydraulic modeling of the gas system. The State should also take into account the role these facilities have had in addressing emergency situations, including extreme weather and wildfires.

1.1.1 How is Storage Designed to Operate in Different Utility Regions?

Subtle differences exist between storage on the PG&E system and the SoCalGas system. Both systems tend to inject gas most of the "summer" season (April 1 to October 31), and withdraw during "winter" (November 1 to March 31). Both use storage to remedy customer imbalances. Both own facilities located close to their largest load centers. Both sell inventory, injection, and withdrawal capacity to non-core customers and marketers via some form of auction that prices those services at market-based rates. The key difference between PG&E and SoCalGas is that, until the 2015 Aliso Canyon incident forced the nearly complete shut-down of the field, SoCalGas had enough capacity that it could lease access for 36% of its overall storage capability to third parties. Aliso Canyon is so large, with geological differences between the East Field and the West Field, that SoCalGas could inject into one part of the field and withdraw from another or even switch from net injection to withdrawal within the same gas day (See Figure 1.1-2 in Chapter 1). This allowed them to give customers enormous flexibility, and enhanced their ability to serve both users of traditional storage services as well as market storage services.[50]

PG&E only offers a relatively small percentage of its storage capacity for sale to the non-core market. Market storage services are offered by independent gas storage companies. All of this independent storage is located in northern California and is connected to the PG&E system. The independent fields are designed to cycle (i.e., inject and withdraw) their full inventory as many as five to six times per year whereas the utility fields realistically can cycle only once per year. The independent operators can do this because they have a much higher ratio of injection capacity to inventory. Injection requires compression, and injecting more gas quickly requires more compression than injecting over the whole summer season. The independent storage is designed to affect arbitrage on a much shorter-term basis than the seasonal utility storage and these storage providers price their service knowing this, with

50. Figure 1.1-2 in Chapter 1 shows SoCalGas withdrawing from some wells while injecting into others.

an eye towards capturing the option value of the service. Independent storage facilities have eschewed any obligation to help provide winter reliability, arguably believing their approach yields higher profits than a business model based on traditional utility cost of service regulation.

The configuration of the two utility systems also gives rise to differences in how they respectively operate storage. SoCalGas appears to be much more dependent on storage to balance its system. This is partly because the SoCalGas system has less available line pack than PG&E by design. All of PG&E's fields are connected to the Bay Area transmission loop or its higher pressure "backbone transmission" system. The independent storage is also connected to backbone transmission and some of the independent storage can also feed into what is known as "local transmission." It is of note that more of the power generators in the north are connected to the higher pressure backbone transmission system; whereas southern California has a larger concentration of power projects inside the Los Angeles basin instead of along the higher pressure mainlines on the way in to the basin. This leads SoCalGas to operate its storage more as a daily shock absorber which PG&E does not have to do.

SoCalGas also tends to experience higher electric generation loads in the mid-to-late summer than PG&E. SoCalGas commonly injects gas in April, May, and June, then backs off injections (or even withdraws) in July through early September, resuming injection in late September and continuing injection well past the November 1 gas industry start of winter. Figure 15 illustrates the injection and withdrawal profile for SoCalGas based on a compilation of daily reported inventory on SoCalGas' Envoy™ public data site for a 15-year period. Negative values represent injections and positive values are withdrawals. The average profile reflects the average of inferred inventory levels for each calendar month and is the best representation of the profile SoCalGas has typically achieved. In other words, in the data period's average May (i.e., the average of all 16 Mays), SoCalGas is injecting about 500 MMcfd. SoCalGas then typically reduces injections (to more like 150 MMcfd) as demand rises in the later summer, then increases to perhaps 200 MMcfd before moving to winter withdrawals. The maximum line represents the maximum injection or withdrawal ever achieved for a particular calendar month in the 16-year period. It illustrates the fact that SoCalGas has withdrawn gas in August and September in some years. An interesting feature shown in the minimum profile is that there have been years in which SoCalGas withdrew very little gas in any given month – and in fact shows the lowest withdrawal for January was actually a net injection, presumably a very warm January.[51]

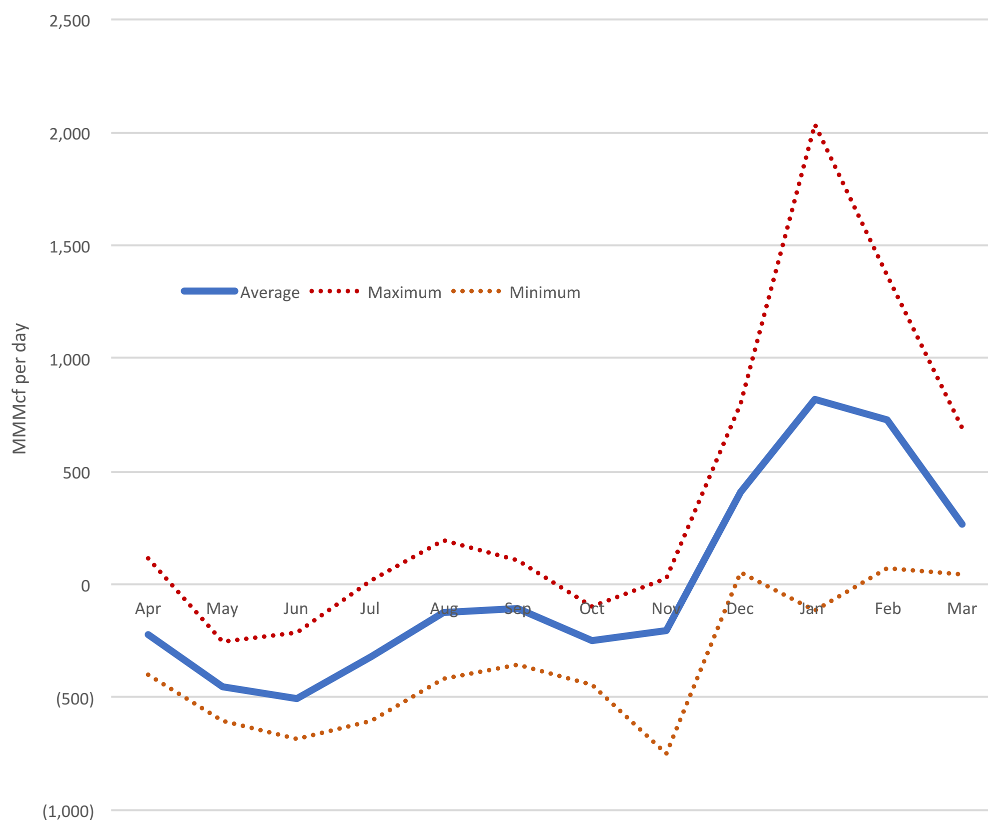

Figure 15. SoCalGas Observed Monthly Injection (negative) and Withdrawal (positive) Profile: 2001 – 2015
Source: Aspen Environmental Group compilation of operational data posted on SoCalGas Envoy™

51. SoCalGas' "winter balancing rules" demonstrate the importance of storage in operating this system. These tighter balancing rules took effect in late winter as the storage inventory dropped, and were designed to preserve remaining gas in storage. Stage One required customers to schedule and deliver into the SoCalGas system at least 50% of the gas they burned over five-day periods (recall that the normal balancing rules allow balances to accrue over a 30-day period) during the November through March "winter" season. Once storage inventory dropped to "threshold 1" (defined as the minimum amount of gas required to meet a peak day plus 20 Bcf), customers had to deliver 70% of their burn every day. When inventory dropped further, to "threshold 2" (defined as the peak day minimum requirement plus 5 Bcf), customers had to bring in 90% of their scheduled burn every day. Trading of imbalances was explicitly not allowed to offset the delivery minimums. These rules were eliminated in 2015 and replaced with a rule allowing SoCalGas to call operational flow orders for under-deliveries of customer-owned gas into its system, giving the utility an immediate mechanism to direct customers to get into balance. CPUC Decision No. 15-06-004.

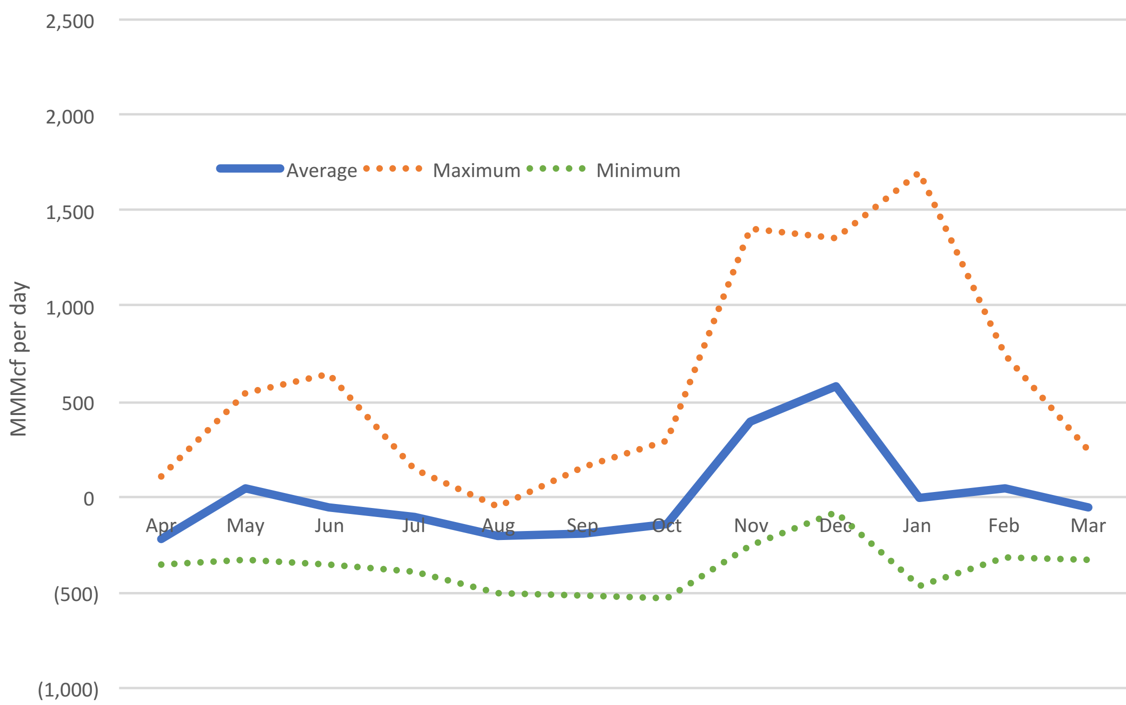

Figure 16. PG&E Observed Monthly Injection (negative) and Withdrawal (positive) Profiles: 2001 - 2015
Source: Aspen Environmental Group compilation of Operational Data posted on PG&E Pipe Ranger

The injection and withdrawal profile among the independent gas storage providers (Figure 17) is much flatter than for either SoCalGas or PG&E (Figure 16) because their clients are using the storage for much shorter-term price arbitrage or market needs for which the operations were designed. They do display a small increase in withdrawals in winter and an increase in injections mid-summer, but the range is much smaller than for PG&E or SoCalGas as the independent operators are not obligated to provide supply to help meet peak demand.

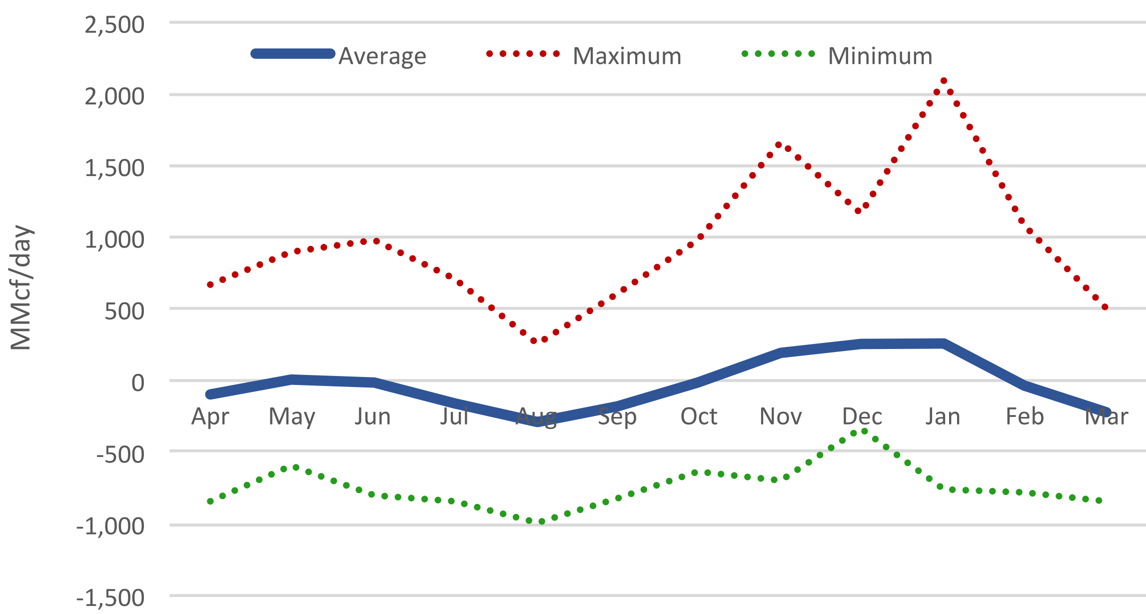

Figure 17. Independent Storage Observed Monthly Injection (negative) and Withdrawal (positive) Profile: 2001 – 2015
Source: Aspen Environmental Group compilation of Operational Data posted on PG&E Pipe Ranger

How SoCalGas operates storage also affects deliveries to San Diego because SoCalGas can use storage to serve the LA Basin, and thereby preserve flowing supply to serve SDG&E.[52] Without this ability, days of insufficient gas supply would turn into a choice between serving San Diego and serving LA. This finding was demonstrated in hydraulic simulations that were subject to independent review by LANL and Walker & Associates. The simulation also shows SoCalGas would have to curtail non-core load in these conditions.

52. Supply comes in to SoCalGas on its Line 2000 fed by EPNG's southern mainline and goes south at Moreno Station to serve San Diego.

Without Aliso Canyon, SoCalGas' system becomes much more constrained because other storage facilities are located farther away from load, are smaller, or have less injection and withdrawal capability. The Playa del Rey facility has very small capacity; it can be emptied very quickly but has so little compression capacity that it takes nine days to refill.[53] La Goleta, located on the coast on the northwestern side of the service area, acts more as a local load-pocket balancer, accommodating the limits on the ability to move gas back and forth from the Basin, out to the Ventura area, and back. Honor Rancho has picked up the overall system balancing work but has less than half the injection and withdrawal capability of Aliso Canyon. Honor Rancho's effective injection capability of 235 MMcfd is less than 10% of total demand on a high demand day (CEC, 2016e). The Summer 2016 Aliso Canyon Reliability Action Plan called for tighter balancing provisions recognizing the much more limited capabilities of the system with less storage. SoCalGas' customers supported those revisions in a settlement adopted by the CPUC (CPUC Decision No. 16-06-021).

In summary, the storage owned by PG&E and SoCalGas operates generally the same way, though SoCalGas sometimes has to use gas from storage in the summer's hotter months and depends much more on storage than PG&E to balance its system. Both depend on storage to meet winter peak load. There is some difference in the withdrawal patterns between the two utilities, and in northern California the independent storage allows arbitragers to inject and withdraw multiple times per year based on short-term market dynamics.

53. Playa del Rey has a working gas maximum inventory of 1.8 Bcf and an injection rate of 0.2 Bcfd. See Aliso Canyon Action Plan to Preserve Gas and Electric Reliability for the Los Angeles Basin. http://www.energy.ca.gov/2016_energypolicy/documents/2016-04-08_joint_agency_workshop/Aliso_Canyon_Action_Plan_to_Preserve_Gas_and_Electric_Reliability_for_the_Los_Angeles_Basin.pdf (Accessed July 2017).

1.1.2 How Storage Affects Natural Gas Prices in California

One might expect natural gas prices to be higher in winter than in summer, owing to winter's higher seasonal demand. Consequently, one also might expect storage to reduce winter prices. To the extent that a gas utility could serve some of its winter demand using gas from storage that was purchased at lower summer prices, the blended price to consumers would be lower than if those consumers faced the natural gas market price each month.

New York and New England are examples of markets that do not have underground gas storage close-by and are regularly short of pipeline capacity to meet winter needs. Prices in markets without storage regularly spike many times the price in California. Figure 18 displays prices at California, Henry Hub, and Massachusetts. The California price tracks relatively closely to the Henry Hub price.[54] We cannot know what prices in California would look like without underground gas storage, but a combination of no storage and insufficient pipeline capacity might reasonably expose California to price volatility and spike magnitudes similar to New England's.[55]

54. Henry Hub is the benchmark measure of U.S. national price; it is used to price forward contracts on the New York Mercantile Exchange (NYMEX). The hub is located in Erath, Louisiana and some 14 different pipelines interconnect there. Considerable underground and salt cavern storage is located within reasonable access of Henry Hub or pipelines that connect to it.

55. During the 2000-2001 California power crisis, low gas storage inventories combined with early season cold (and some potential price manipulation) caused natural gas prices to spike. Storage injections were low that year because EPNG's southern mainline near Carlsbad exploded in August 2000 and was out of service for several months. A CPUC staff report also cited low precipitation that year that limited hydroelectric power and kept demand for gas high. It also cited non-core customers having filled only half the volume of storage to which they were entitled. An Assembly committee investigation concluded that EPNG used a contract for capacity on the EPNG pipeline (held by affiliate El Paso Merchant Energy) to manipulate the market. Chief ALJ Curtis Wagner at FERC also found that EPNG illegally exercised market power by withholding capacity. Essentially, EPNG did not tell shippers who nominated to constrained receipt points that other unconstrained receipt points were available for use. See "FERC Judge says El Paso Unit Withheld Natural Gas Supplies from California," Oil and Gas Journal, September 24, 2002. Found at http://www.ogj.com/articles/2002/09/ferc-judge-says-el-paso-unit-withheld-natural-gas-supplies-from-california.html (Accessed May 2017).

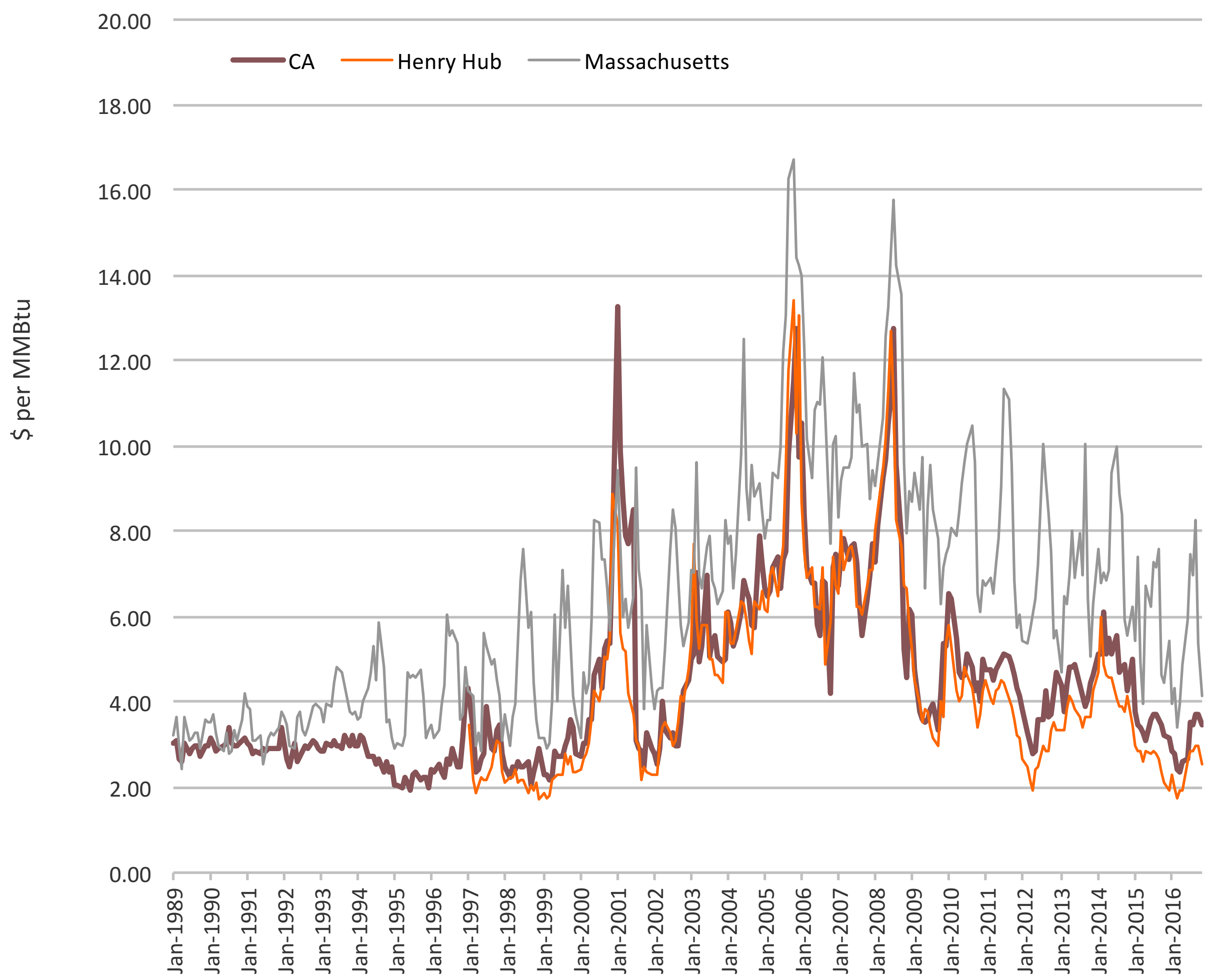

Figure 18. California, Massachusetts, and Henry Hub Natural Gas Prices
Source: Energy Information Administration

Consultancy ICF prepared a 2009 study for the CEC that provides an excellent review of gas storage economics and their impact in California. ICF provided a conceptual analysis of the value of storage from a public and private perspective. It noted that during the 2000-2001 power crisis "additional working gas and/or deliverability would have mitigated some of the disruptions in the electricity market and could have had significant positive impacts for the broader economy in California. More broadly, even a cursory examination of gas industry trade publications indicates the importance of storage inventories on natural gas price levels." ICF also noted that storage market participants are not homogeneous: different participants value different aspects of storage differently and that California has been seen as an industry leader in fostering storage investment at the "right" level (ICF International, 2009).

1.1.3 How the Natural Gas System Treats Generators and Affects Electricity Reliability

This section describes the State's reliance on gas generation for electricity reliability. It highlights how that role has changed and how the gas system's rules were set up when gas was not as important for electricity reliability. Electricity generators are non-core customers. They have no more and no fewer rights to priority of service than any other non-core customer. They are subject to the same nominations and balancing rules as any other non-core customer. In theory, they should receive no special treatment.

In reality, generators receive lower priority of service than other non-core customers. Regardless of the curtailment rules specified in adopted CPUC policy or gas utility tariffs, from the perspective of the gas system operators, the electricity system has more options than other non-core gas customers, such as the ability to shift generation to plants located elsewhere, use demand response, or to import more power. Other non-core gas load such as oil refining does not have this flexibility. Curtailing the refinery industry can create significant consequences. Sudden outages of either electricity or natural gas service to a refinery can damage refinery equipment.[56] It can take days to bring a refinery back up once it is shut down. Electric utilities often preserve service to refineries during outages by placing them in protected load blocks.[57] SoCalGas, in 2016, received approval to protect from curtailment a minimum quantity of natural gas load for each of the refineries to avoid a sudden and complete shutdown.[58] So, while other non-core customers, by the letter of the rules, should share in gas curtailments after the first 40% of electric generation load is cut, this does not happen in practice and electricity generators will still likely take the brunt of curtailments. The Aliso Canyon technical assessments and reliability action plans released in April 2016, August 2016, and May 2017 reflected the expectation that electricity generation will be curtailed first.

More generally, storage was built to serve peak winter load for core customers and was not designed and built to serve peak electric generation. At the time the gas system was

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56. The CEC, reflecting the importance of petroleum to California's economy, held a workshop on June 17, 2016 to obtain industry testimony on some of the physical risks and impacts of either electricity or natural gas outages at the refineries. See http://www.energy.ca.gov/2016_energypolicy/documents/2016-06-17_workshop/2016-06-17_presentations.php (Accessed July 2017). See also CEC, 2015 Integrated Energy Policy Report and work of the Petroleum Market Advisory Committee.

57. This approach was approved in CPUC Decision No. 01-04-005.

58. CPUC Decision No. 16-07-008. SoCalGas' submission to implement these tariff changes, allowing each refinery customer to indicate their "minimum usage requirement," can be found at https://www.socalgas.com/regulatory/tariffs/tm2/pdf/5089 (Accessed August 2017).

designed, electric generation primarily used fuel oil, coal, or hydropower, not natural gas.[59, 60] The gas system offered discounted rates to customers with seasonal or intermittent load, which helps to round out use of the system, that otherwise would have been entirely paid for by core customers. This is reflected in CPUC Decision No.62260, from July 1961:

> *A gas utility may affect economies, and thus provide firm service at lower rates, by selling gas during such off-peak periods for industrial consumption on an interruptible basis. The interruptible class of customers is thus an important class, both from the standpoint of the utility and from the standpoint of the customers. However, it is fundamental that interruptible industrial gas is not sold on such terms as would endanger the required firm supplies or as would place an economic or price burden on firm customers. This fundamental principle is also applicable to sales of transmission pipelineable quantities of gas.*
>
> *As a general proposition when gas is available for use by interruptible customers, the choice of burning gas or an alternate fuel lies with such customers and is practically wholly dictated by value and price considerations, including air pollution regulations and the economics of investment in standby or storage facilities as well as the direct influence of the relative costs of the respective fuels. It follows, therefore, that interruptible industrial gas prices generally cannot exceed the costs of using alternate fuels. In California, the alternate fuel is almost without exception fuel oil.*

In some cases, generators "lean" on the system and see how far they can get without incurring a price penalty. Many pipelines do allow informal flexibility as long as this does not compromise their systems. Load diversity helps allow this to the extent one customer's over-delivery offsets another's under-delivery. Otherwise, generators have to either stay in balance like other customers or be penalized. Neither PG&E nor SoCalGas (or SDG&E for

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59. As late as the mid 1980's, PG&E had power plants with adjacent steam boilers, one running on natural gas and the other on fuel oil.

60. The practice of curtailing gas to electric generators was reinforced in the 1970's, when natural gas was in short supply in interstate markets. Many states experienced natural gas curtailments, including California. See U.S. Department of Energy, 1978 Distributed Energy Systems in California's Future: Interim Report Volume I, Section 4.1.3. Page 49. Congress directed states, via the Natural Gas Policy Act of 1978, to adopt end-use priorities to allocate gas to highest-priority uses during these times of shortage. The Fuel Use Act, also adopted in this same period, prohibited use of natural gas as a fuel for base load power generation. The Fuel Use Act is found at Public Law No. 100-42. However, the 1978 Public Utilities Regulatory Policy Act allowed gas to be used in cogeneration. As supply concerns eased and natural gas markets liberalized, enactment of the Public Utilities Regulatory Policy Act allowed gas fired cogeneration developers to become some of the first non-utility, or merchant, generators. They offered scales of investment and risk with lower capital costs, ease of siting, and time to construct that were faster than alternatively-fired units. See Elder, "Implications of Greater Reliance on Natural Gas for Electricity Generation," American Public Power Association, 2010. See also, Tussing and Tippee, "The Natural Gas Industry: Evolution, Structure and Economics,"1995.

that matter) offer tariffs with more flexible features to electric generators. Generators are expected to follow the same balancing and other tariff rules as other non-core customers.[61]

By and large, generators tend not to subscribe to storage service.[62,63] A review of SoCalGas' "Index of Customers" in December 2015 showed that none of the gas storage was sold to generators. This means that generators were not direct users of tariffed natural gas storage service, not even to manage their own imbalances. It is possible that some gas marketers who do subscribe to storage could have used their storage rights to help manage imbalance accounts for generators to whom they sold gas. In a given nomination window, a marketer could, in theory, change their nomination to inject or withdraw more gas to correct an imbalance (Appendix 2-1 contains a description of the nomination process). The five nomination windows each day, however, do not coincide with the hours in which a generator might want to vary their usage, nor do they provide the opportunity to submit a variable nomination.[64]

While generators do not subscribe to storage service, they do benefit from storage and this benefit helps assure electricity reliability. Technical analyses in the Aliso Canyon Action Plan demonstrate the risk to electricity system reliability when the ability to use storage is diminished. This benefit occurs by virtue of the way the utilities use storage to balance their system. SoCalGas uses storage to balance its system on an hourly basis, while allowing the liberal balancing tolerances, that yield great flexibility to customers, to vary their loads within a gas day. SoCalGas could use injections to eliminate excess gas or use withdrawals to provide additional gas supply and even go from one to the other within a gas day. Other electricity systems, without storage, may use hydro-electricity, imports, economy energy sales, demand response, pumped hydro storage, and now battery storage, to manage their swings in demand.

61. Some interstate pipelines offer hourly load service tailored to generator needs. But those services cost more than normal firm transportation service, and unless the generator is an integrated utility they cannot pass the cost on to ratepayers. So, generators avoid buying gas from these pipelines.

62. ICF's 2009 study for the CEC also made this point.

63. An exceptional case occurred when a new independent gas storage facility was denied a Certificate of Public Convenience & Necessity (CPCN) by the CPUC. The facility had contracted for all of its capacity with a municipal utility (not subject to CPUC jurisdiction) for the purpose of enhancing reliability to a large gas-fired power plant and several cogeneration facilities. Despite the contract, the CPUC denied permission to construct the Sacramento Natural Gas Storage (SNGS) project, citing concerns about public safety.

64. There is some talk within the industry of potentially allowing nominations for hourly-variable quantities. Whether they succeed or not remains to be seen, as does how such can be implemented without access to gas storage somewhere along the pipeline. We return to this subject in discussing alternatives to gas storage.

ICF described the role of gas storage this way:

> *Natural gas storage capacity in close proximity to the firming generator offers a physical option to manage pressure fluctuation resulting from intermittency. The requirement to manage the pressure in the pipeline in proximity to the plant and throughout the system is the combination of compression and a source of gas. Since the gas is moving at a speed of 15 to 30 miles per hour in the pipeline … the source of gas must be located close enough to the line segment where pressure may be dropping to fill the line pack. Compression with no source of gas on the inlet side of the compressor is not sufficient to manage pressure. If gas can be withdrawn from storage close to the firming plant, either directly upstream of the compressor or utilizing compression at the storage facility, pressure can be stabilized and managed as the firming plant ramps up (ICF International, 2001).*

Other regions do not depend on natural gas for electricity in the same way California does. Many of these regions have shifted from dependence on coal, oil, or nuclear power to using gas more as a baseload while California is shifting away from gas and increasingly relies on renewable energy. Also, in many of those regions, the gas-fired generating plants have dual-fire capability and air permits to allow the use of other fuels. The Midwest System Operator (MISO), for example, has 6.6 GW of dual-fired capability within its footprint (MISO Policy & Economic Studies Department, 2013). In the Northeast and Southeast, generators commonly have back-up fuel capability for times when natural gas is not available; both of these markets are pipeline-capacity constrained and have no underground gas storage facilities located within them.[65] Finally, in some of those regions, power plants commonly have reduced gas availability in winter months when pipeline capacity serves seasonal winter heating load. In New England for example, even if a generator was willing to pay for firm capacity, it has long been common for pipelines to offer firm service to new load only for summer and shoulder months.

The relation between load, pipeline capacity, and storage in California also differs from other parts of the country where without storage they would have to build pipeline capacity to meet their gas load winter peaks. If there is no summer gas load that can use that capacity, consumers pay for capacity that sits unused during those months. Many of those regions use smaller above-ground gas storage facilities known as liquid natural gas (LNG) needle peakers. The needle peakers do not address the monthly average day peaks in winter (greater pipeline capacity is still being built to address that), but they address the extreme "needle" peaks that can occur on an especially cold day within a month.

65. Georgia is another example, where the electric utility would not even buy power from a generator that does not have back-up fuel.

California's gas storage system provides back-up for contingency events affecting electricity generation. Contingency events on the electricity system can result in a sudden need to increase the burning of natural gas in power plants. NERC has contingency reserve requirements that require unloaded generation be available to be fired up and operate to cover contingency events such as the loss of generation or the loss of a transmission line. Such resources must be able to get up and running on a 15-minute notice (NERC BAL-002 Requirement 4). Once activated, the balancing authority has 60 minutes (and sometimes only 30 minutes) to restore the contingency reserves or have resources standing by to respond to the next potential contingency event (CAISO, 2015).

There can also be local areas with limited import capability and fewer native generating resources. LADWP, for example, is one of these. The city of Riverside is another (SCAQMD, 2016a). Riverside stated that it must fire up gas generation should its single transmission import line go down.[66] Pasadena is another (CAISO, 2016a).

For winter 2016-17, the joint agencies (i.e., CPUC, CEC, CAISO and LADWP) performed a technical assessment and calculated that a minimum of 22 MMcfd of gas would be needed to avoid blackouts after shifting as many resources as possible elsewhere and with no contingency events occurring. In the case of a most severe single contingency event (known as an "n-1" event), the minimum increases to 74 MMcfd, and 96 MMcfd should an n-1 event occur for both CAISO and LADWP (CPUC, 2016f). The amount of gas required to keep the lights on in the summer after shifting resources increases by more than an order of magnitude to 1,750 MMcfd for a 1-in-10 peak day and 1,870 MMcfd with an electricity n-1 event.[67]

Importantly, contingency events, being unpredictable, would occur at a random point during a gas day. The gas quantity nominated and scheduled in advance would be insufficient to serve this additional gas requirement. In this instance, reliability is achieved by virtue of PG&E and SoCalGas being in a position to provide a balancing service that accommodates changes in gas demand. California's gas storage is what allows them to do this today.

Such contingency events can transcend California's agencies and balancing authorities. As part of its summer 2017 reliability assessment, NERC coordinated with Western Electricity Coordinating Council (WECC) to analyze reliability risk for California and the potential for effects to cascade into the western electricity interconnect. WECC particularly assessed generation availability and unit stability within the LA Basin, whether transmission lines

66. Briefing discussion with City of Riverside on Aliso Impacts, April 2016.

67. Aliso Canyon Risk Assessment Technical Report Summer 2017 Assessment, May 2017, p. 17. Shifting generation to locations outside the LA Basin is more achievable in winter than in summer because winter electricity demand is lower, requiring fewer plants to operate to meet demand and lower loading on transmission lines.

would be overloaded and whether low generation in the LA Basin could result in insufficient voltage support that could result in system collapse and risk undermining the entire western interconnection. NERC concluded the following:

> *There is a minimum amount of generation that must be online in the L.A. Basin to provide voltage support to the local system and allow power to be imported. Without this generation, there is a high likelihood of voltage collapse within the L.A. Basin and risk to the interconnection if such a collapse is not quickly isolated. LADWP and CAISO have the detailed tools to determine the minimum level of generation that must remain on-line for system stability and have estimated 1300 MW to be the "must-run" capacity to support transmission import capability. WECC's analytics affirmed that this is a reasonable estimate (NERC, 2017).*

In California, electricity balancing authorities worry about wildfires (California Climate Change Center, 2012). Fires create the risk of either burning a major transmission line or de-energizing it for a time. Under these conditions, utilities are able to call on gas-fired generation to replace generation made inaccessible by fire. The Blue Cut fire in August 16, 2016 is an example of an event which caused additional gas supply to be called upon to support electric reliability. [68] Every year, thousands of acres of forests in California and elsewhere burn, mainly in summer months. For example, there were 2,900 fires burning on 106 square miles across California in July 2017, more than twice last year's average (May, 2017). During recent wildfires in Santa Rosa, hundreds of power poles and the lines and transformers they carried exploded. When fires occur, they sometimes force electric transmission lines offline (e.g., WECC, 2002; CAISO, 2002, 2003, 2007, 2008; FERC, 2013), which can cause sudden loss of generation capacity and may last many days, similar to the intermittency occasionally experienced by wind and solar generation. These losses hamper the State's ability to provide adequate power to load centers, particularly during the peak electricity demand season. Moreover, wildfires often occur during hot weather, when the demand for air conditioning-driven electricity is highest. This combination of factors increases the reliance on backup strategies, including gas generation. Gas generation may require sudden supplies of gas served by underground storage, to provide local generation and, when necessary, load curtailment. Wildfire frequency and intensity may be increasing with climate change (e.g., U.S. EPA, 2016).

68. Operating data from SoCalGas' Envoy system show total gas system sendout on the day of the Blue Cut Fire of 3,438,000 Dth, with 410,000 Dth withdrawn from underground gas storage and system receipts of only 3,028,000 Dth. Envoy archives also show that SoCalGas had a low operational flow order (OFO) in place for this event asking shippers to bring their supplies within 5% of demand. If SoCalGas posted the archived hourly data one might be able to explain the apparent discrepancy by which total receipts plus withdrawals exceeded sendout for the day (as offset by individual hours in which sendout was higher than receipts).

Gas-electric coordination efforts nationwide began after release of the American Public Power Association's natural gas study in 2010 and the extreme southwest cold in February 2011 that led to electricity outages and natural gas curtailments (discussed above in Regulatory and Operational Options (Including Market Rules) to Help Replace Underground Gas Storage). Several of the organized markets and the FERC began to focus more attention on linkages between gas used for electricity generation and the ensuing reliability issues. Discussions have focused on the nomination windows, an arcane provision still in many tariffs known as the "no-bump" rule that can be particularly troublesome to generators, linking the start hour of the gas day with the start hour of the electricity day, and other possible remedies (Black & Veatch, 2012). Although many meetings of the North American Energy Standards Board (NAESB) occurred, various reliability transmission organizations conducted studies, and FERC held a rulemaking, progress has been modest. CAISO has added a staff position to focus on gas-electric issues.

The above discussion demonstrates the State's reliance on natural gas for electricity reliability. It highlights how that role has changed and the gas system's rules being set up when gas was not as important for electricity reliability.

1.2 Factors that May be Causing Role of Gas Storage to Change

The role of gas storage may be changing as markets and policies evolve. Specific instances we can identify now include price changes, demand changes, and generation changes.

Prices

Lower prices with reduced volatility have reduced the value obtained from use of gas storage to seasonally arbitrage gas. Accordingly, consumers and risk managers may decide not to hedge. Arbitrage itself does not require physical storage because financial contracts can be purchased that lock in winter prices ahead of time. (Financial arbitrage cannot address reliability in the way that physical storage can). The physical storage owned and used by the utilities for their core customers, however, represents a depreciated asset so the cost to use storage may be less than the transaction cost of a seasonal financial hedge contract. This may make physical storage financially more attractive. Customers and regulators also might be more (or less) comfortable with the operational risks and financial exposures of physical storage than with financial contracts. Financial contracts also are typically kept confidential, reducing market transparency, whereas storage injection and withdrawal volumes are at least reported, which plays some role in enhancing market efficiency and competition and therefore prices.

Flatter prices (i.e. lower price volatility) as documented in Figure 19, may also reduce interest in the short-term arbitrage provided by independent storage.[69] Recall that gas marketers largely use independent storage for shorter-term price arbitrage, and to enhance liquidity. Contracts for that storage are often multi-year so changes to them may lag behind market conditions, but anecdotal reports indicate that reduced price volatility has reduced arbitrage opportunities, and thus reduced subscription to independent storage. A look at the SoCalGas Index of Customers for underground gas storage from December 2015 versus the list of contract holders in April 2017 shows that the number of non-core customers and gas marketers holding storage rights decreased from about 35 Bcf to only 3.2 Bcf. The more recent part of that decrease was likely caused by the situation at Aliso Canyon. Also, SoCalGas' announced in February 2017 that its Storage Safety Enhancement Plan (SSEP) would significantly further reduce its injection and withdrawal capability through late 2017.[70]

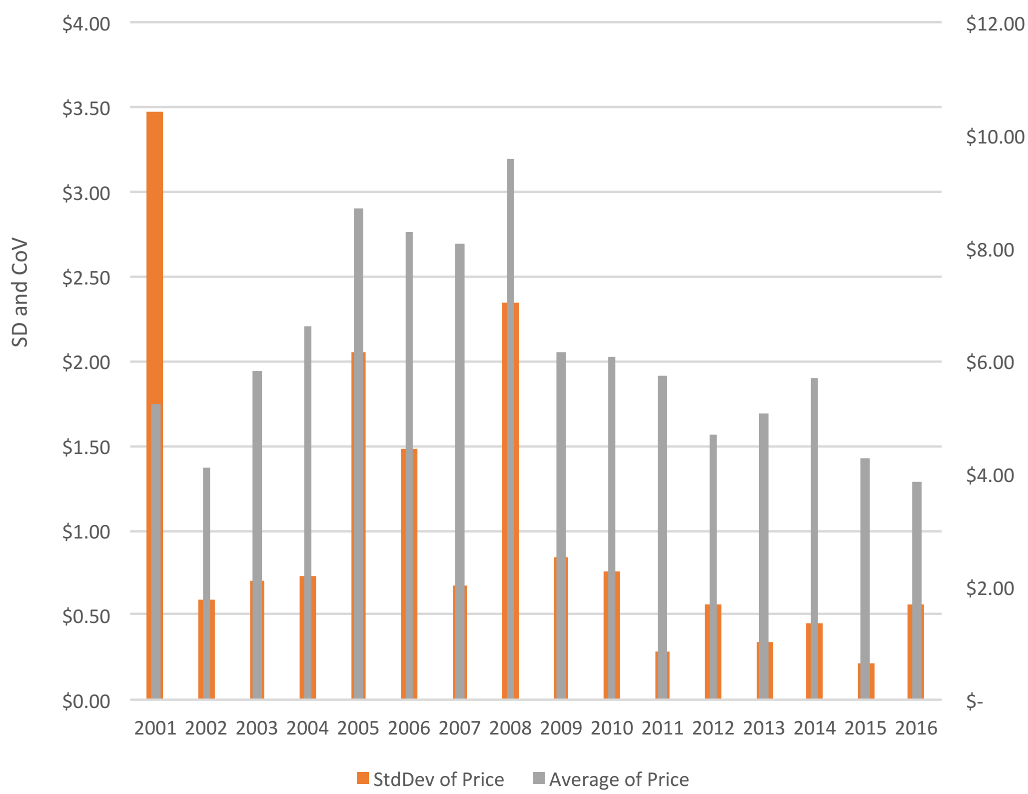

Figure 19. California Natural Gas Price Volatility
Source: Aspen Environmental Group analysis

69. Prices are the same California Citygate prices reported by EIA as used in Figure 13.

70. The CPUC directed SoCalGas on March 16, 2017 to modify the Storage Safety Enhancement Plan (SSEP) to preserve withdrawal capability of 2.046 Bcf.

A Potential Shift in the Use of Independent Storage

At a public customer meeting on May 11, 2017, PG&E announced a proposal to close its Los Medanos and Pleasant Creek gas storage facilities based on an assessment of reliability. The cost of this closure was not released to the public but the proposal was included in their 2019 Gas Transmission and Storage Rate Case filed with the CPUC on November 17, 2017 (CPUC Application of PG&E). PG&E said it would reconfigure its gas services to more explicitly focus on intra-day balancing and contract with the independent storage providers to provide the gas needed to meet core winter requirements. This would essentially restructure the independent storage providers by giving them an obligation to serve core customers. No reliability or system gas analysis was released to the public with the meeting, and PG&E retreated to settlement discussions (confidential under CPUC rules) to discuss details. As of October 1st, the proposal has not yet been formally filed at the CPUC and remains subject to litigation and approval there. If approved, this plan would represent a profound shift in the use and role of independent storage in California.

Demand changes

Declines in the use of natural gas would also reduce the need for storage, all else being equal. The California Energy Commission (CEC) and the two gas utilities all forecast natural gas demand (total, peak, and electric generation demand) to decline over the next ten years. PG&E, in fact, forecasts demand to decline at an average rate of 0.6% through 2035 (2016 California and Electric Utilities 2016). About one-third of that is attributable to energy efficiency among core customers. The other two-thirds is attributable to a combination of increasing renewables offsetting gas-fired generation (which decreases electricity generation demand for natural gas), along with a significant increase in gas transmission rates charged to generators (which also decreases electricity generation for natural gas). In describing its forecast in the 2016 CGR, PG&E said that greater use of gas-fired generation to back-up renewables with load following and other ancillary services was likely, but was not captured in the forecast. The CGR does not report on or address hourly gas load. That means that the utilities have no published estimates of the impact on their gas systems from significant changes to use patterns by generators – and no analysis beyond what SoCalGas performed for the 2014 WIEB study or the April and August 2016 Aliso Canyon technical reports.

Demand for gas will change because California has been adding additional intermittent renewables to the grid that will reduce the aggregate need for burning gas in power plants. However, the remaining use of gas may be “peakier,” or more variable because gas-fired plants are increasingly called upon to meet the sudden increases in net electricity demand that occur, for example as people get home in the afternoon and begin to consume electricity just as solar production begins to wane. The gas system was not configured to support large increases of sudden use in the afternoon. Currently, the system accommodates large increases either serendipitously, or because storage has been available and the utility has sufficient control to allow it to make up the imbalance created on its system when the generator fires up.

The public record does not yet provide detailed studies with stakeholder review examining the ability of California's gas utilities to serve large ramps in electric generation. ICF has done some general work in which they suggested enlarging pipeline segments near power plants in order to increase line pack capability. ICF also noted that the capabilities of marketers to provide shaped supply (i.e., other than on an even, ratable basis as required now) will depend on the underlying infrastructure including such enlargements (Crook, 2012).

One study performed for the Western Interstate Energy Board (WIEB) includes a look at how natural gas use patterns might change with more renewables generating electricity in California.[71] The study does not assess system operations without use of underground gas storage. Its findings are public but the underlying transient hydraulic analysis was conducted by SoCalGas and was not subject to detailed critical review.[72] SoCalGas' analysis for the WIEB study found that in a 50% renewables penetration case, SoCalGas could handle afternoon ramps as gas-fired generation came on to replace renewables, as long as supply and demand were already matched and its system was therefore in balance. SoCalGas added the further caveat that the dispatch of more "quick-start" gas-fired generations could cause dramatic pressure drops that would look much like a system failure to gas system operations control staff.

SoCalGas warned in the Quadrennial Energy Review (QER) conducted by DOE in 2014 that quick-start plants were changing use of gas on its system.[73] SoCalGas and SDG&E deliver natural gas to 79 individual power plants representing 20,000 MW of generating capacity. The relative locations of those plants are shown in Figure 20.

71. Energy & Environmental Economics, Inc., Natural Gas Infrastructure Adequacy in the Western Interconnection: An Electric System Perspective (2014). Aspen Environmental Group provided support to the CEC's participation in this study.

72. While Western Interstate Energy Board (WIEB) tried to use a contractor to build and analyze a hydraulic database, they found no sufficiently detailed public source of the necessary data that would allow them to produce useful results. SoCalGas therefore presented its analysis and results to a working group that included representatives of the California Energy Commission, Lawrence Berkeley National Lab (LBNL) as independent observers for Department of Energy (DOE), and WIEB. Aspen Environmental Group participated in the WIEB working group on behalf of the CEC. SoCalGas worked with the Joint Agencies in a similar way that they did to compile the Summer 2016 Aliso Canyon Risk Assessment Technical Report.

73. Presentation of Beth Musich (2014), found at https://energy.gov/sites/prod/files/2014/07/f18/qermeeting_denver_musich_presentation.pdf. Accessed May 2017. Musich cited those plants recorded a maximum load in winter of 1,000 MMcfd (on November 13, 2013) and a maximum in summer of 1,835 MMcfd (on August 13, 2012).

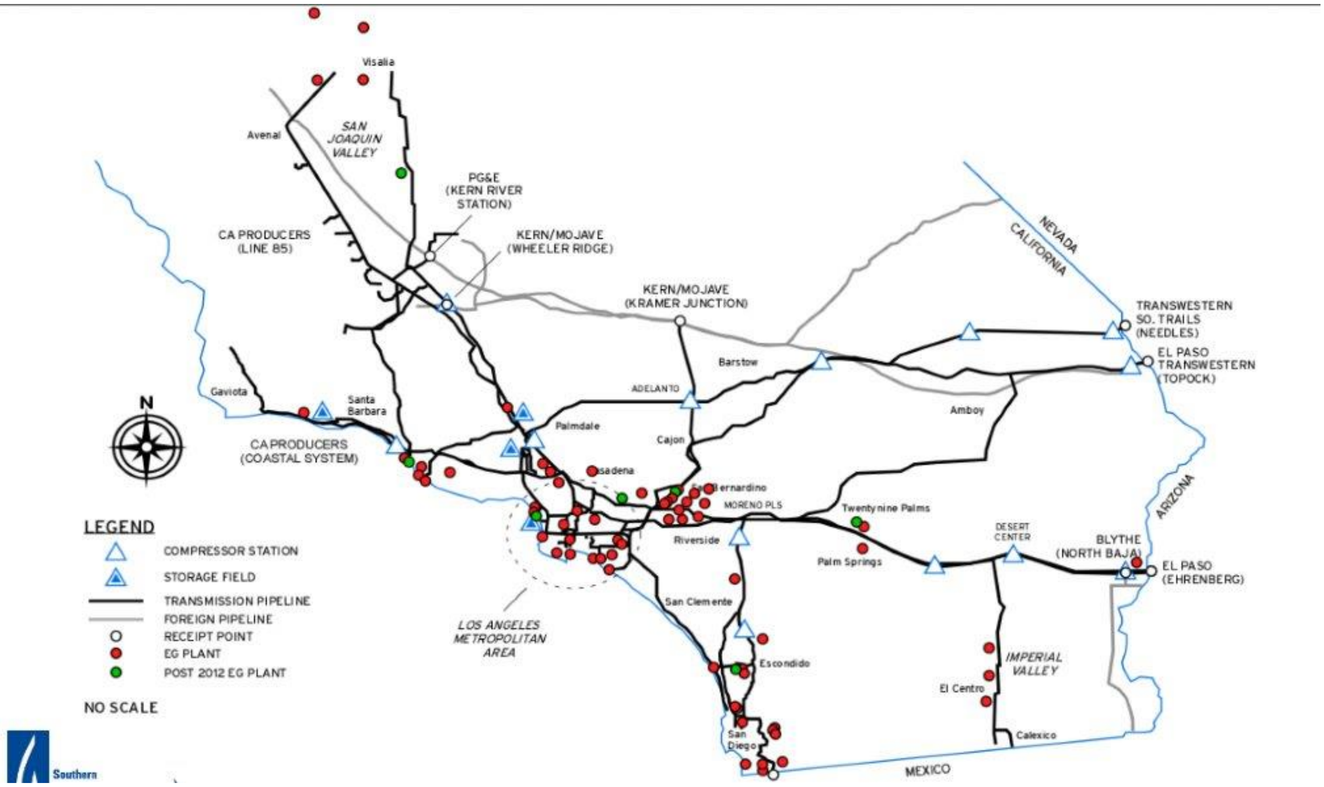

Figure 20. SoCalGas and SDG&E Electricity Generation Customer Locations
Source: SoCalGas DOE QER Presentation

The newer plants have been built with quick-start technology that can fire up to full operation in as little as ten minutes. More specifically, they take nine minutes to go from zero to 50% of their hourly demand and one minute to ramp up from there to full output. This demand profile contrasts starkly to older power plants that take up to two hours to go from zero output to full generation. SoCalGas noted that it sees a drop in system operating pressure of 40 psig, and has seen a drop of up to 70 psig, due to firing up quick-start plants. The sudden drops in pressure are illustrated in Figure 21.

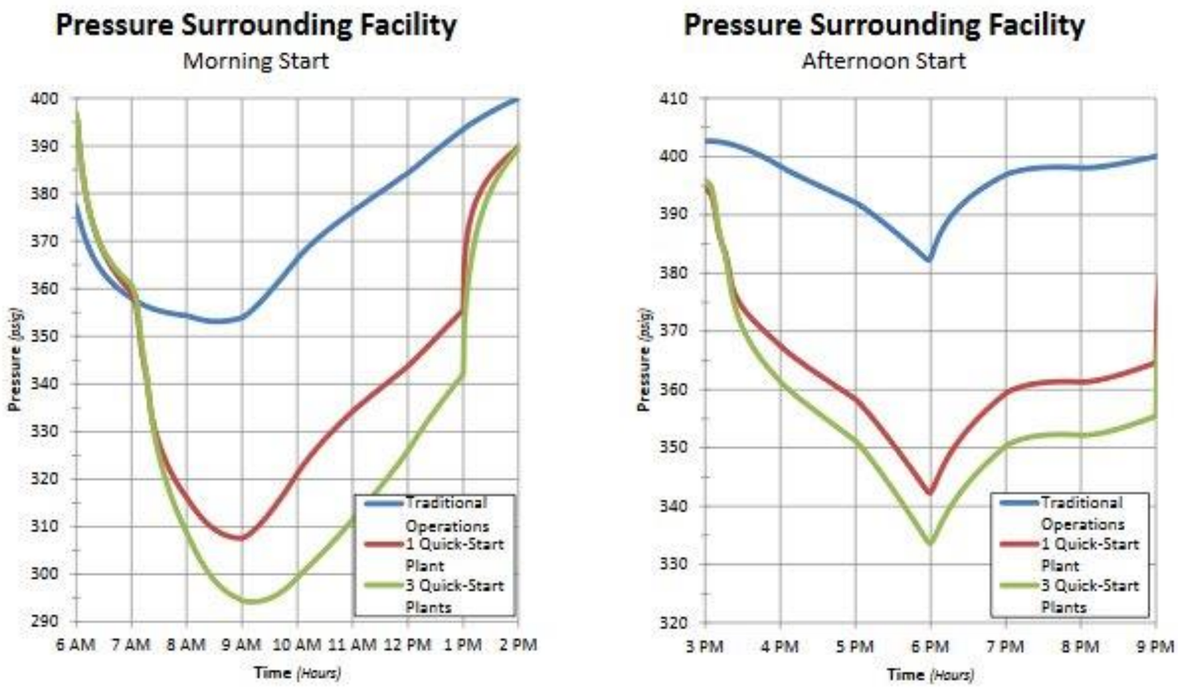

Figure 21. SoCalGas Pressure Drop with Quick-Start Units
Source: SoCalGas Contribution to WIEB Study

In trying to assess reliability impacts in the aftermath of the 2015 Aliso Canyon incident, the joint agencies learned that SoCalGas uses Aliso specifically to help balance its system. PG&E indicated during the WIEB study that its Los Medanos field, located in the Highway 4 corridor near several key power plants and refineries, is useful to them for handling afternoon ramps by power plants.[74]

Conclusion 2.9: Without gas storage, California would be unable to accommodate the electricity generation ramping that now occurs nearly every day and that may increase as more renewables are added to the grid.

74. Interview with CEC staff.

1.3 Impacts on performance or gas delivery from problems at gas storage facilities.

A list of gas storage facility incidents, including Aliso Canyon, appears in Table 9. Additional details on some of these events can be found in a 2007 history of gas storage facility incidents compiled for the Sacramento Natural Gas Storage facility (Weatherwax).

Other than re-dispatch of the electricity system by CAISO and LADWP in the aftermath of the Aliso Canyon well leak, the only other incident that appears to have affected customers is the PG&E McDonald Island incident in December 2015. That event was not a failure of the McDonald Island facility per se, but rather human error. A valve left open after maintenance work allowed undehydrated (i.e., "wet") gas into the distribution system, which then froze due to cold temperatures. Reports of leaks from the now-closed Montebello gas storage field that resulted in local evacuations of residents and complaints about Playa del Rey are easy to find in the press.[75] This is not saying the system can withstand all interruptions in storage service, just that these incidents were not large enough, or occurred at a time when they could have little impact.

Table 9. Gas Storage Facility Incidents and Impact to Customers.

Owner	Field	Year	General Nature of the Incident	Impact to Customer Service
PG&E	Los Medanos	2011	Valve failure in open position during hydrotest resulted in gas leak	None
PG&E	McDonald Island	2016	Small leaks discovered due to testing in wake of Aliso Canyon leak; DOGGR mandates testing regimen	Field shut during summer; no impact to deliveries
PG&E	McDonald Island	2015	Whiskey Slough valve left open allowed "wet" gas into Line 57B and then froze in a district regulator and pressure limiting station	Communities of Discovery Bay and Byron lost gas service on a cold day; customers sent to warming centers
PG&E	McDonald Island	1993	Explosion in gas conditioning (moisture extraction) plant	None
PG&E	McDonald Island	1974	19-day fire sparked by explosion during drilling of new well	None
PG&E	McDonald Island	1982	levee broke; island flooded	None
SoCalGas	Aliso Canyon	2015	Well blowout due to the breach of an injection well casing. Safety valves had been removed in the 70s, causing the leak to persist unabated until discovered.	Mitigation measures and mild weather prevented gas curtailments and electricity blackouts
SoCalGas	Aliso Canyon	2013	Production casing leaks at depths adjacent to oil production sands	None

75. See, for example, http://articles.latimes.com/1990-08-05/news/we-133_1_underground-natural-gas-storage. Accessed July 2017.

Owner	Field	Year	General Nature of the Incident	Impact to Customer Service
SoCalGas	Aliso Canyon	2008	Well casing corrosion - 400 psig at surface	None
SoCalGas	Aliso Canyon	1994	Well crushed during Northridge quake	5-day field outage but demand down after quake so impact unclear
SoCalGas	Aliso Canyon	1975	Sand erosion in piping led to a blowout and well fire	None - partial shutdown of operations
SoCalGas	East Whittier	1970s	Gas migration - injected gas being produced by a nearby well	None - field shut in 2006; removed from rate base in 2009
SoCalGas	Honor Rancho	1975 - 2008	Gas migration from Castaic to surface via faults	None - impacted oil production in nearby wells and killed trees at surface
SoCalGas	Honor Rancho	1992	Casing shoe leak due to sidetracking	None
SoCalGas	Montebello	1950s -1980s	Gas migration due to original grout not withstanding higher pressures	evacuations
SoCalGas	Montebello	2003	Gas migration due to original grout not withstanding higher pressures	evacuations - ultimately resulted in storage field closure in 2003
SoCalGas	Playa del Rey	1940s -2008	Gas migration into Venice structure via faults and wellbores	None - some stored gas lost
SoCalGas	Playa del Rey	2013	Well over-pressurized during injection, causing vent valve to release gas. Brief fire and shut in of facility	None
SoCalGas	Playa del Rey	2003	Broken compressor valve led to activation of a vent valve, spraying a gas/oil mist that coated surrounding homes	None
Standard Oil of California	El Segundo	1993	Gas migration due to caprock not being gas tight/faulted	None - field closed in 70s after gas detected in a nearby housing development
Wild Goose	Wild Goose	1999	Leaking flange discovered due to pressure increase	None

Source: Aspen Environmental Group compilation

1.4 Alternatives to Underground Gas Storage (to 2020)

The first portion of this section considers facilities and supply options that could help replace underground gas storage. The second portion looks at operational and market changes that might reduce the need for storage. In both sections, we focus on what is known now and expectations to 2020. Many, but not all, of the alternatives reviewed come from suggestions in the Joint Agency reliability action plans or public comment. Virtually no detailed studies are available in the public domain looking at using these to specifically replace any aspect of underground gas storage and some may find the analysis here limited. Even based on this limited assessment, we find that these alternatives cannot address the overarching need to use stored gas to meet winter demand (or balance the gas system on an intraday basis) by 2020, either because they provide insufficient relief, impose extraordinary costs or take too long to construct.

Recall the seven uses of gas storage as described above:

1. Meeting higher demand in winter months
2. Sustaining flat aggregate wellhead production by producers serving California
3. Meeting individual daily needle peaks in winter and summer
4. Intraday balancing of transportation nominations for all customers (but especially key to electricity reliability)
5. Local stockpile in case of pipeline failure or reduced interstate supplies
6. Seasonal and short-term price arbitrage
7. Allowing market liquidity

The magnitude of gas required to meet winter demand and winter peak demand dominates these uses. Any viable replacement in the 2020 timeframe would have to demonstrate that it could effectively match supply to demand in the winter. Consequently, the following sections first assess whether a given approach could replace gas storage for the purpose of meeting winter demand.

1.4.1 Facility, Supply and Demand Options that Could Help Replace Underground Gas Storage

Here, we identify and assess options that could increase capacity or decrease demand and in so doing could help replace the need for underground gas storage. We describe pertinent details for each, as well as offer ballpark costs and note potential safety considerations. They include adding new intrastate and possibly some interstate pipeline capacity, new electric transmission, LNG or CNG in containers, LNG peak shaving units, renewable natural gas, and energy efficiency and demand response. All entail significant cost; none could completely replace underground gas storage by 2020, although some could reduce the need for storage in this timeframe.

New Pipeline Capacity. Both our intrastate pipeline capacity and interstate capacity are too small to meet winter peak demand without gas from storage. Table 6 shows calculations of the amount of pipeline capacity required to meet the forecast level of winter peak demand for 2020, if underground gas storage is eliminated. All else being equal, meeting winter demand would require building 4,334 MMcfd (4.3 Bcf per day) of new intrastate pipeline capacity. As a rule of thumb, a single large-diameter (i.e., 36" or 42") pipeline and associated compression can deliver at least 1,000 MMcfd. In other words, replacing storage would entail building at least four additional pipelines and associated compressor stations (if existing compressors do not have excess horsepower to support the new pipelines). This new capacity will need to run from interconnects with the interstates to the interconnects where gas storage currently delivers into the local transmission system. The pipelines downstream of storage should already be appropriately sized. Table 1 showed 10,631 MMcfd (10.6 Bcf) of firm interstate capacity able to deliver gas to the state line. Interstate pipeline capacity of 10.4 Bcf is not sufficient to meet the design peak demand of 11.8 Bcf. So, besides the intrastate capacity of 4.3 Bcf per day, California would also need additional interstate pipeline capacity of approximately
1.2 Bcf per day.

The FERC approves construction of interstate pipelines and its policy does not provide a large barrier to construction. For over twenty years, FERC policy has been to approve expansions, subject to environmental review and mitigation, whenever a sponsor is willing to take the risk of potential unsubscribed capacity at rates using a well-understood cost recovery methodology. EIA's posting giving an overview of the process for building interstate pipelines cites an average time for FERC review of 15 months and an average overall from announcement and open season to solicit shipper commitments to the pipeline in-service date of three years (U.S. EIA Natural Gas Pipeline Development and Expansion, 2017).

Ruby Pipeline, which runs 42" diameter pipe the 680 miles from Opal, Wyoming to Malin, Oregon with four compressor stations is the most recent greenfield addition to western pipeline capacity (FERC Docket No. CP09-54). Its sponsor announced launch of an open season to solicit binding shipper commitments in February 2008 (*Energy Business Review,* 2008). It filed its request to be granted a certificate of public convenience and necessity (CPCN) in January 2009. The final Environmental Impact Statement (EIS) was published in January 2010 and FERC granted CPCN approval in April 2010. Construction began that July (which suggests the pipe was ordered before the final CPCN was granted) and the pipeline was placed into service one year later, in July 2011. Fourteen shippers hold contracts for firm transportation totaling about 1 Bcfd (this is less than the full 1.5 Bcfd of capacity Ruby offers, which implies its sponsors took the financial risk on the difference between those commitments and the full 1.5 Bcfd).[76] Ruby reported to FERC a near-final total cost of $3.55 billion, some $590 million more than estimated. Rates for firm transportation on Ruby run $1.14 per Dth of space reserved plus $0.01 for every Dth transported (FERC Docket No. CP09-54).

If the utilities were going to build new intrastate capacity inside California, they would apply to the CPUC. California's intrastate pipeline capacity involves obtaining approvals, doing the design work, and completing the associated environmental impact work to expand. SoCalGas filed an application to build a new segment of pipeline that would have connected its northern mainline to its southern mainline using a route generally running from Adelanto to Moreno. In that application (A. 13-02-013), SoCalGas argued it only needed to ask permission to recover the cost of the facility in rate payments. The CPUC ruled that a complete showing of need with environmental assessment was required before construction could begin. After hearings and proposals for alternatives, the CPUC, in Decision No. 16-07-015, denied permission to construct.

The most recent expansion of mainline capacity within the state may be PG&E's expansion in 1993 from Malin, through Antioch (with a connection to storage at McDonald Island), ultimately terminating at Kettleman. This major expansion doubled the capacity of the mainline bringing gas in from Canada at Malin, and allowed that gas to flow all the way south to Kettleman. This allowed some gas from the south to be displaced or swapped such that customers in southern California could purchase Canadian gas. The expansion was the California portion of what was known as the PGT/PG&E Expansion Project and ran all the way to Alberta. At the time, the PGT/PG&E Expansion was said to cost more than $1 million per mile (Bechtel PGT/PG&E Pipeline). For the much more recent example of Ruby Pipeline, construction costs totaled $5.2 million per mile (or $3.6 billion for its approximate 700-mile distance) with a capacity of 1.5 million Dth per day.[77]

Perhaps constructing a new pipeline in California will cost less than the recent example of Ruby Pipeline. Sometimes pipelines can add a second line between compressor stations (known as "looping" because it creates a loop between the two stations). Subject to confirmation, most of the intrastate capacity existing within California is already looped. Sometimes a compressor is sized low relative to the maximum pressure a pipeline can achieve such that capacity can be added cheaply by merely adding compression. This may be feasible for Ruby or Kern River or Gas Transmission Northwest (GTN). El Paso Natural Gas (EPNG) may have existing capacity that is under-utilized that California could obtain and avoid building a complete new pipeline for the full length between supply basins and the state line.

76. A Dth is 10 therms and is equal to 1 MMBtu. Pipeline tariffs typically state rates in dollars per Dth per month and capacity is reserved in Dth per month.

77. Or about 1.44 Bcf per day assuming a heating value of 1.04 million Dth per Bcf.

Constructing even one pipeline and getting it into service by 2020 is close to infeasible at this point given the time it takes for policy approval, environmental analysis, obtaining right-of-ways, and construction. Constructing one or two by 2025, however, might be achievable; and, if the demand forecasts are correct, the new pipeline capacity needed to replace storage would be smaller by then.

Ruby may be a reasonable proxy for the type of facilities (in terms of pipeline diameter and compression) and the total mileage needed to cover Topock to Malin, using the assumption that existing routes are the natural paths for expansion, which seems reasonable as a first cut.[78]

Finding: Based on recent pipeline construction costs, we estimate a total cost of close to $15 billion to add 4.3 Bcfd of large-diameter intrastate pipeline capacity and one new interstate pipeline, should California have no underground gas storage.

Converting this $15 billion capital, or investment, cost to a cost per Dth would require assuming a capital to debt structure and a forecast of throughput over some cost recovery period. Whatever the rates turn out to be, customers would be paying for the entire capacity year-round, but only use it part of the year. The annual revenue requirement for underground gas storage is undoubtedly lower than that, with the caveat that new safety requirements may impose higher costs to refurbish and operate those facilities.

Replacing storage with a dependence on supplies delivered through new pipelines will introduce new risks to the gas system. The West (outside of Alberta) has little underground gas storage capacity and lacks the geology to build more storage. The locations that could host storage tend not to be located near interstate pipelines and the West is largely disconnected from the so-called "production-area" storage of the Gulf Coast (see Figure 2 to see where storage is located US-wide). Consequently, eliminating storage in California and replacing it with pipeline capacity means we must assume 4.3 Bcf more production would be available as needed to match California's full demand on a peak day. In a competitive market and with proved reserves available to produce gas and even export it, this does not seem unreasonable.[79] That being said, this study does not perform a supply-demand analysis to look at production by supply basin and their capability of meeting California peak demand or what other gas market adjustments might occur if California had no gas storage. However, the choice of replacing storage with new pipelines would move control of some reliability issues out of the State.

78. Online distance calculators suggest 256 miles from Topock to LA and 572 miles from Malin to LA, so Ruby's 680 miles might be a little shorter than what we could end up needing to build to replace storage

79. See CEC, 2017 Natural Gas Outlook, forthcoming, and Energy Information Administration, Annual Energy Outlook 2017.

Finding: Supplying California's full winter peak day demand completely with gas delivered via pipeline on the day it is needed instead of using gas stored in California pushes the problem of matching supply with demand onto upstream gas pipeline operators and producers.

Conclusion 2.10: Construction of additional pipelines to replace underground gas storage in the 2020 timeframe would cost approximately $15B, would be extremely difficult to get done by 2020, and would shift the risk of supply not meeting demand to upstream, out-of-state supplies.

LNG Peak Shaving. LNG peak shaving units with tanks to store the liquefied gas above ground could replace underground gas storage.[80] California has not needed LNG peak shaving units because we have underground gas storage, but nearly 100 of these facilities exist in the U.S. today. The one nearest to California is in Lovelock, Nevada. Large gas utilities and pipelines such as Atlanta Gas Light and Florida Gas Transmission own several such facilities. Besides Atlanta, Memphis, Omaha, and Minneapolis are among the cities where meeting winter peak demand is facilitated by LNG peak shavers. These units provide above-ground gas storage: they take pipeline gas that is excess to requirements in low demand seasons, chill it into LNG and store it in a large tank, then reheat it when needed to meet demand and inject it back into the pipeline. At one time, the combined sendout capacity of LNG peaking plants in the U.S. represented about 10% of total peak capacity (Mesko, 1996). The Gas Technology Institute offers extensive information about operating such peak shaving facilities (2013). Chicago Bridge and Iron Company (CB&I) has built more than 90 of these facilities in the U.S. and elsewhere.[81] Accordingly, training technology and expertise to build these facilities is readily available.

80. LNG is natural gas that has been chilled to its liquid state, where it takes 1/600th the of the space it takes up as a gas.

81. See http://www.digitalrefining.com/data/literature/file/1247008557.pdf for more detail on CB&I's experience in this area, including photographs of facilities.

Three recent projects illustrate what such facilities might cost California; their costs and capabilities range widely.[82, 83, 84] Taking the simple average of these projects' capital cost per MMcfd of sendout, is $2.25 million. Replacing 4.3 Bcf of underground gas storage with above-ground LNG peak shavers works out to a capital investment of approximately $9.675 billion. This capital investment would ostensibly be recovered through rates over time from customers deemed to benefit from the facility.

Liquefaction (chilling) pipeline gas requires energy, as does vaporizing (reheating) it back to its gaseous state. This energy use would produce GHG emissions and potentially criteria pollutants. Siting and land requirements may pose obstacles, depending on the sites selected.

Storing LNG also poses safety concerns. A blast in 2014 at a Williams Partners facility in Plymouth, Washington (located along The Williams Companies' Northwest Pipeline) injured five people and caused $46 million in damage. The blast occurred when the plant returned to liquefaction activities at winter-end. The Pipeline and Hazardous Materials Safety Administration (PHMSA) failure investigation report cited auto-ignition of a gas-air mixture left in a pipe after routine winter-end purging as the apparent cause (PHMSA, 2016).

Finding: California could replace all underground gas storage required today with LNG peak shaving units and meet the 11.8 Bcfd extreme winter peak day demand forecast.

Conclusion 2.11: Replacing all underground gas storage with LNG peak shaving units to meet the 11.8 Bcfd extreme winter peak day demand forecast for 2020 would be extremely difficult to permit and would require about $10B.

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82. Puget Sound Energy (PSE) is currently in the process of constructing its Tacoma LNG plant (Puget Sound Energy, 2017). The facility will be located at the Port of Tacoma. Tacoma LNG will liquefy and store pipeline gas until needed on a later day, thereby providing peak gas supply to the PSE Seattle-Tacoma service area. Tacoma LNG will also provide cleaner fuel (replacing bunker fuel) for ships traveling between Tacoma and Alaska. The facility will be able to liquefy 20.7 MMcfd of pipeline gas into 250,000 gallons of LNG. It will then be able to vaporize the liquid gas and send 66 MMcfd back into the pipeline (City of Tacoma, n.d.). Its single LNG tank will be able to store eight million gallons of LNG, which equates to 661 MMcf. The anticipated installed cost of the facility is $310 million (Ecology and Environment, Inc., 2015).

83. The second project, the Pine Needle LNG storage facility in Guilford County, North Carolina, was placed into service in 1999 and interconnects to Transcontinental Pipeline. Pine Needle has the capability to liquefy 20 MMcfd of natural gas (similar to the 20.7 MMcfd capability of the Tacoma LNG facility). Its ability to store the equivalent of 4 Bcf, however, is about six times more than at Tacoma and its ability to vaporize and return to the pipeline 400 MMcfd is also significantly more than Tacoma. The cost to build Pine Needle was $106 million, in then-current dollars (Pine Needle LNG Company, LLC, 2010).

84. The third project, Yankee Gas Service's (Yankee) LNG facility in Waterbury, Connecticut was placed into service in 2009 at a then-current cost of $108 million. Yankee offers 6 MMcfd of liquefaction capacity, 1.2 Bcf of storage, and 60 MMcfd of vaporization capability (CBI, 2008).

Containerized LNG. Intermodal containers designed to specifications approved by the International Organization of Standardization (ISO) can deliver liquid natural gas to remote customers. These containers are 40 feet long and 8 feet square, with fortified walls and protective frame structures outside the perimeter of the tank. They can fit on any type of transport that can carry a standard shipping container and container ships, railways, or trailer trucks can all deliver containerized LNG.

The ISO containers can hold the liquefied gas for up to 75 days (meaning they can serve as storage). Returning them to pipeline gas requires use of a portable vaporizer (re-heats the chilled liquid to its gaseous state). Each container can hold up to 10,000 gallons, which when converted back to ambient air temperature is 0.830 MMcf of natural gas. (A relatively efficient gas-fired power plant would use between 8 MMcf to generate 1 MW for an hour, so approximately 10 containers would be required per MW), or a 50-MW gas fired electric generator would require 500 containers — for enough natural gas to generate electricity for one hour. A number of applications can serve as examples for California.[85]

Conclusion 2.12: The number of containerized LNG units required to generate each MWh suggest containerized LNG does not appear viable at the scale required to replace California's 4.3 Bcfd winter peak need for underground gas storage use. It may, however, have application in meeting system peaks for a few hours or supporting power plant demands for a few hours. Though it would require 2,000 containers to support a 50 MW

85. In terms of known uses, EIA cites a 90,000 gallons per day, three-unit plant under construction at Port Allen, Louisiana that will take containerized LNG to users located far from natural gas pipeline service. EIA also cites use of containerized LNG coming from Florida to supply a 120-MW power plant the island of Jamaica is converting from oil. That appears to use 22 containers of LNG per day, without saying how many hours the plant would operate each day or at what level of output. In a demonstration project, late in 2016, two LNG containers (manufactured by Hitachi) were hauled to Fairbanks, Alaska on the Alaska Railroad and then 4.5 miles via flatbed truck (Alaska Railroad, 2016). They returned to Port MacKenzie to be refilled with LNG before returning on the next overnight freight to Fairbanks. Local news reports on briefings to first responders suggest the Federal Railroad Administration encourages responders to let the gas vent, should a puncture occur. The Railroad believes transportation by rail will be safer than via truck and safer than the risk associated with other petroleum products shipped by rail to Fairbanks currently. Others disagree (Buxton, 2015).

Hawaii Gas is using containerized LNG purchased from Fortis in British Columbia and a small liquefaction facility owned by Clean Energy in Boron, California (Hawaii Gas, 2016). The Hawaii project consists of 70 ISO-certified containers, 2 new cryogenic pumps, 3 new LNG vaporizers, and an LNG pump skid. EIA reports Hawaii Gas is still exploring building the infrastructure to support docking of bulk LNG tankers to floating regasification and storage units. Hawaii consumes only 3 Bcf of natural gas per year, the lowest in the U.S., none is used for power generation and the LNG will replace only 30% of the syngas that Hawaii Gas manufactures from naphtha. The capital expenditure for the LNG container project shown in Hawaii Gas' application to the Public Utilities Commission of the State of Hawaii is $12.8 million (Hawaii Public Utilities Commission, 2014). Some parts of the application were redacted and so it is not clear if the capital expenditure includes the cost for Hawaii Gas to purchase the 70 containers (CEC, 2016b).

power plant for four hours, and these containers would have to be transported to a power plant, which would incur potential safety issues, increased emissions, and complexity.

CNG In A Box™. Compressed gas (which is different than liquefied gas) stored in containers,[86] such as the GE version trademarked as "CNG In A Box" could perhaps provide some storage service. GE presented this concept in comments filed at the CEC after the April 2016 Joint Agency Workshop on Aliso Canyon Action Plan for Local Energy Reliability in Summer 2016 (CEC, 2016e). The container includes the compressor, a gas dryer, a gas cooler, pressure relief valves, and a blowdown tank (see Figure 32). Quotes run about $600,000 for one container that can compress between 1.5 and 2.5 MMcfd. That does not include interconnection from the container to a pipeline and back or from a pipeline to the container to a power plant, and additional "tube" trailers would be needed to store gas after compression.

GE suggested 1 compressor box plus 12 tube trailers and 2 pressure reduction skids could cover 4 hours of generation by a single 50 MW LM 6000, although the box requires a whole day to compress that much gas at a rate of 0.5 MMcf per hour. Replacing the full 4.3 Bcf pipeline capacity deficit California would face, absent underground gas storage, would require close to 8,000 boxes and would only deliver for one day before needing a day to compress again. They could not cover the multiple days of gas from storage often needed in the winter.

Four hours of gas to a 50 MW combustion turbine is the rough breakeven point; at less than that, the CNG appears to be more economic than the LNG.[87] Safety and the implications of a more distributed gas system with storage located nearer to end-users become the issue. However, no data on reliability or leak rates appears available.

Conclusion 2.13: As with the containerized LNG, far too many "CNG In A Box" containers would be needed to replace California's underground storage, but applications such as providing a few hours of gas at a specific location such as a peaking power plant or a refinery could make sense.

86. CNG is sometimes also used in vehicles.

87. Liquefying gas costs more than compression, but LNG can store more gas per container.

Figure 32. GE's CNG Technology Solution
Source: Photo courtesy of BHGE

LNG via Ocean Terminal. LNG import terminals in California have presented controversy (in no small part due to safety concerns not discussed here) including a facility proposed in the 1970s at Point Conception and five or more proposals presented in the mid-2000's. Based on this experience, this analysis does not contemplate building multiple LNG terminals along the California coast. Sempra, however, did build and still owns an LNG import terminal at Ensenada in Baja, Mexico known as Costa Azul. This facility can deliver up to 1 Bcf per day of natural gas into pipelines.[88] The configuration of SoCalGas' system means that SDG&E receives virtually all of its gas via the Moreno to Rainbow corridor coming from the EPNG southern mainline that also serves Los Angeles.[89]

88. The Costa Azul storage tanks can hold 320,000 cubic meters of liquefied gas (which converts to 6.9 billion cubic feet reheated back to gaseous state). Costa Azul connects through the Transportadora de Gas Natural de Baja California (TGN) pipeline to a lateral pipeline that crosses the International Boundary to deliver gas into the SDG&E system at Otay Mesa. The border crossing at Otay Mesa is sized to accept up to 400 MMcfd. Low natural gas prices resulting from the shale boom mean that the economics do not support LNG imports and the facility, while fully subscribed and paid for via reservation charges, remains little used. EIA reports that imports have averaged only 4% of the terminal's nameplate capacity since 2011.

89. Flows on that lateral pipeline are southbound only, meaning that physically, the gas imported as LNG cannot flow further north than the SDG&E system.

Serving SDG&E load with gas imported as LNG would allow more flowing supply to continue on into the LA basin, thereby augmenting SoCalGas' operational flexibility. [90]

The Joint Agencies' Action Plans raised the possibility of using the Sempra LNG terminal in this way. Hydraulic simulation performed by SoCalGas for the agencies in preparing the reliability action plans demonstrates how Moreno Station becomes the pivot point for the SoCalGas system when Aliso Canyon is not available. As pressures inside the LA basin drop, the SoCalGas operators end up having to decide whether to send gas reaching Moreno into the basin versus down the Rainbow line into San Diego. SDG&E's load is forecast to vary in a normal temperature and hydro-electric production year from a low of 268 MMcf per day in May and a high of 386 MMcf per day in December, averaging 337 MMcfd. These values are shown in Table 10. In a 1-in-35 cold and dry hydro year (not shown in the Figure), December demand is forecast at 430 MMcfd. The load in San Diego that can be served from Costa Azul LNG terminal can offset some of the need for gas from underground storage.[91]

Table 10. SDG&E Gas Demand Forecast: Normal Temperature and Hydro.

	2017 (MMcf/d)												
Customer Class	*Jan*	*Feb*	*Mar*	*Apr*	*May*	*Jun*	*Jul*	*Aug*	*Sep*	*Oct*	*Nov*	*Dec*	*Average*
Core	200	204	167	150	119	102	94	91	92	103	153	212	141
Non-core	158	167	141	149	149	238	250	257	274	198	167	174	194
Co. Use & LUAF[12]	3	3	3	3	2	3	3	3	3	3	3	4	3
Total	361	374	311	302	270	343	347	351	369	304	323	390	337

12 Company use is compressor fuel; LUAF is "Lost and Unaccounted For," some of which is vented, leaked, meter error, or differences between calendar month and meter read cycle.

Source: SDG&E, 2016

90. One might wonder if moving gas south from Ehrenberg on North Baja and then west on TGN to Otay Mesa and into San Diego is an option. Analysis of the throughput on North Baja showed an average use of 326 MMcfd with a maximum in August of 449 MMcfd, meaning that the pipeline is sufficiently utilized that it cannot provide the same certain quantity needed to meet SDG&E gas load as the LNG terminal can. See http://www.tcplus.com/North%20Baja/SharedFolder/DisplayFile/c27101a64d2b4af9462997202cf1a81193e68974?downloadType=Presentations, slide 53 (Accessed July 2017).

91. To date, the Sempra utilities have, without being very specific, cited concerns about running afoul of rules designed to limit favoritism in transactions between corporate affiliates as an obstacle. But discussions with FERC and CPUC staff have produced no compelling reason that any affiliate transaction rules stand in the way of completing the purchase of LNG and delivering it in this way. No comments from SoCalGas on the Joint Agencies Reliability Action Plans suggesting this idea have cited any reason why using Costa Azul to serve SDG&E is physically infeasible.

LNG costs more than domestically-produced natural gas transported to San Diego via pipeline. (LNG prices have dropped considerably and are now trading at perhaps double U.S. domestic natural gas prices delivered via pipeline (Thomas, 2017).) In addition, SDG&E and Sempra have no obligation to buy gas for non-core customers, which represent a portion of the SDG&E gas load, and thus would require some sort of additional regulatory approval to use LNG to serve SDG&E. Several power plants are located along the international boundary and the pipeline between Costa Azul and Ehrenberg. Review of flows and contracts on that pipeline as well as LNG cargos shows that the power plants are not being served by LNG from Costa Azul but from gas flowing from EPNG into Baja Norte and Transportadora and there is not sufficient capacity free on those pipelines to serve SDG&E.

The cost of an average of 337 MMcfd (total SDG&E gas demand forecast in Table 10) for five years at an assumed likely price of $3.50 per MMBtu is $2.2 billion. If LNG were purchased and delivered into SDG&E at a world price of $6 per MMBtu, the annual cost would be $3.7 billion (Thomas, 2014). This represents a net cost increase of $1.5 billion over pipeline-delivered natural gas over the five years. It is not clear that SoCalGas would in fact have to pay the world LNG price; a 2006 settlement of anti-trust claims requires Sempra LNG to sell and SDG&E and SoCalGas to purchase LNG supplies up to 500 MMcfd at the California border price minus two cents for 20 years.[92] At the same time, SoCalGas indicated in response to data requests in Application No. 13-12-013 that it required CPUC authorization before purchasing gas from Sempra's Costa Azul LNG facility, and that it had not investigated purchasing it due to a landed cost of LNG of $15.65 Per MMBtu reported by FERC (SoCalGas, 2014a). As the settlement applies to volumes "that Sempra Companies currently have contractual rights to purchase and that Sempra Companies do not deliver or sell to: (1) CFE; or (2) other Mexican entities," and no such sales of LNG have yet occurred, it may be that Sempra no longer holds such commodity purchase rights.

Prior CPUC action facilitates importing LNG into southern California; in 2006, the CPUC approved creation of the receipt point at Otay Mesa and integration of the gas transportation rates of SoCalGas and SDG&E. Combining their two rates was approved on the basis that a single transmission rate would enable customers of both utilities to receive gas from Otay Mesa on an equal footing, avoiding so-called rate "pancaking" in which costs of one system are layered on top of those from another (CPUC Decision No. 06-04-033, 2007). Sempra LNG argued in this proceeding that gas delivered at Otay Mesa would benefit

92. The "Continental Forge" settlement (available at https://www.sdge.com/sites/default/files/regulatory/AppendixA_0.pdf, (Accessed April 2017) addressed claims arising from the 2000-2001 power crisis accusing SoCalGas and SDG&E of involvement in price manipulation. The settlement was approved on July 20, 2006 by the Superior Court of the State of California, County of San Diego, J.C.C.P. Nos. 4221, 4224, 4226, and 4228. A separate settlement was entered into related to claims by Southern California Edison and by California's Attorney General on behalf of the CPUC. The CPUC in Decision No. 06-12-34 closed all of its proceedings investigating the actions of SoCalGas and SDG&E citing the settlements.

customers because it would travel less distance than gas delivered via Ehrenberg and that it would enhance system and supply reliability.

Since the willingness to build new large ocean terminals is likely low (discussed above), the Joint Agency Action Plan team did explore the possibility of bringing an Excelsior-type barge with on-board liquefaction capability to the southern California coast. These are commonly known as FSRUs, or floating storage regasification units. The agencies abandoned the idea after discussion with SoCalGas, which indicated the delivery of those supplies into the LA basin would require the addition of compression. No hydraulic simulation of the gas system was conducted to demonstrate this and there may be FSRU's available today that can achieve high pressure sendout (Excelerate Energy, 2017).

In short, using the existing LNG terminal at Costa Azul can be implemented now and without building any new physical facilities.[93]

Conclusion 2.14: Augmenting gas supply to San Diego with LNG from Sempra's terminal in Mexico would provide a short-term, albeit relatively small (on the order of 300 MMcfd), impact on the need for gas storage in Los Angeles at a small marginal cost, and would not require construction of new facilities.

Fuel Switching

Renewable Natural Gas and Power-to-Gas. The label 'natural gas' came about when naturally-occurring gas produced from underground reservoirs became available to replace gas that was manufactured from coal in various towns and consequently known as "town gas." Methane gas, or CH4, can in fact be produced via a number of methods from a variety of sources. Biogas is called 'renewable' when it is produced from the natural decomposition of organic matter in landfills, livestock manure, and wastewater treatment plants (Environmental and Energy Studies Institute, 2010). Once processed to remove impurities and meet existing pipeline standards, it can be injected into the utilities' natural gas pipeline systems and the CPUC refers to it as "biomethane (CPUC Decision 14-01-034)."[94]

Biogas can be produced from food waste, animal waste, or captured from landfill decomposition. Appendix 2-6 outlines progress with renewable natural gas. Food waste can be diverted from landfills into biogas production (CalRecycle, n.d.). In fact, California recently implemented AB 1826 (Chesbro, 2014), requiring the recycling of organic waste by source generators of that waste, and AB 341 (Chesbro, 2011), which mandates that 50% of organic waste be diverted to productive uses by 2020. Both of these efforts will lead to the

93. The degree to which the LNG needle peakers or the terminal's vaporization can load follow within a gas day requires additional investigation.

94. CCST has a separate study under way at the request of the CPUC to conduct an independent scientific assessment of the minimum heating value and maximum siloxane specifications for the delivery of biomethane to public gas pipelines.

collection of food and other waste streams that are high in organic content for digestion. According to CalRecycle, approximately 6 million tons of food waste are landfilled every year (CalRecycle, 2016). The East Bay Municipal Utility District (EBMUD) found the average value of methane production from food waste to be 11,400 ft3/ton of total solids (U.S. EPA, 2008). Assuming that half of the total landfilled food waste is diverted to anaerobic digestion, the annual quantity of methane available from food waste in California is 34,200 MMcf. This equates to 94 MMcfd, or only 1.5% of the 6,072 MMcfd average daily California gas demand for 2016 shown in the California Gas Report. Even if the biomethane quantity were higher, the impact for storage depends on its production profile: if its production cannot be tailored to follow demand patterns, then it has no beneficial impact to the state's need for underground gas storage.

Finding: In addition to the fact that only small amounts of renewable natural gas are likely to be available by 2020, storing this gas to help meet winter demand and to provide daily ramping would still require use of underground gas storage.

Diesel Fuel. In theory, virtually any gas-fired generator can be configured to burn diesel fuel. Until around 1990, it was common for the electric utilities to switch between natural gas and diesel, or even low sulfur waxy residue (LSWR) depending on natural gas availability and price. Southern California Edison (SCE), for example, owned 120 miles of liquids pipeline extending from Bakersfield to Long Beach, one tank farm, several storage facilities adjacent to 7 electric generating stations, and 11 heating and pumping stations. Initially, these facilities provided the primary fuel supply to SCE power plants. They became secondary in the 1980s when natural gas became the fuel of choice for economic and environmental reasons, after which they were used only for emergency back-up fuel.[95] This lasted until August of 1999, when the CAISO agreed the dual-fuel requirement was "no longer required for electrical system reliability (CPUC Decision No. 03-07-031, p. 2)." The CPUC approved the sale of the facilities in 2003 and noted that many of the "station facilities" (i.e., those within the foot print of the power plant) were removed.

Today only a handful of the gas-fired generators in California hold air permits to burn diesel or any petroleum-based fuel other than natural gas.[96] The older facilities that used to hold such permits realized they would not be able to renew them, due to air quality concerns, and removed the holding tanks, spill capture berms, and other equipment needed to burn liquid fuels. Newer power plants, especially those constructed by independent generators, never even installed the equipment needed to burn diesel fuel or oil, due to the expense. These decisions were also heavily influenced by their economics – any increase in cost

95. According to the EIS for Lodi Gas Storage's Kirby Hills expansion, the last time power plants switched to fuel oil because gas was not available was a 10-day period in winter 1998-99. See http://www.cpuc.ca.gov/environment/info/aspen/kirbyhills/pea2/1_intro.pdf, p. 1-3 (CPUC).

96. The exception being LADWP. There may also be a handful of small peaker turbines that can still burn diesel.

directly reduced profits. Additionally, their non-recourse lending agreements concurred that there was no need for back-up fuel because with California's excess pipeline capacity and vast underground gas storage resource, natural gas would always be available at some price.

Critics of the 2016 Aliso Canyon Action Plan suggested that a relatively new fuel, known as Amber 360, should be available to allow power plants to burn a diesel-like product with drastically lower air quality consequences. LADWP has three key power plants, isolated from CAISO, which have maintained the physical ability to burn diesel for black start purposes.[97] LADWP explored market opportunities to obtain Amber 360 and found that the fuel was not available in the quantities needed. Their turbine manufacturer also stated that the metals content of the fuel would void their warranty on the generators. LADWP was able to find a low-nitrogen diesel (below what is typically contained in CARB diesel) from its existing supplier of fleet vehicle fuel and applied to the South Coast Air Quality Management District (SCAQMD) for a permit to test and use it at the three power plants.

SCAQMD held hearings in which it questioned witnesses not only about the diesel fuel burn plan but about the risk to electricity reliability absent the ability to burn diesel and subsequently granted the variance (SCAQMD, 2016). LADWP has indicated this fuel was available at the market price for diesel. [98] Units had to be recommissioned to run on diesel fuel, existing bunkers filled in anticipation of potential curtailment, and revisions made to fuel handling protocols. Although dealing with diesel is difficult, LADWP has this option available in case it is needed to maintain electric reliability. This short-term option is not available to other generators.[99]

Changes to electricity sector demand

Options that would reduce the use of gas used for electricity generation are to bring in electricity through new transmission, store electrical energy (instead of chemical energy stored in gas) to use to meet peak demand, or reduce the demand through energy efficiency and demand side management approaches. None of these would significantly help to meet the winter peak demand in the 2020 timeframe but could alleviate the use of gas storage in the summer.

Finding: Gas-fired furnaces overwhelmingly supply building space heating in California and this use results in the winter peak demand for gas. California has no policies specific to

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97. "Black start" is what operators call bringing the electricity system back from complete blackout with all facilities out. The controls used on a black start unit include a DC auxiliary support system, an ignition source, a gas turbine and a diesel generator (Morris, 2011).

98. Email correspondence with LADWP's Marlon Santa Cruz, 2/14/17.

99. Because of the limited nature of this option, we did not assess the broader petroleum market implications (i.e., price and availability) greater use of diesel fuel would also have.

electrification of building heat, therefore the source of building heat will not likely switch to electricity for several decades (for more information, see Chapter 3).

The highest recorded total gas demand in the recent five-year period was 11.2 Bcfd (December 9, 2013), and the highest projected 2020 peak winter demand is 11.8 Bcfd (Table 6). However, statewide gas import capacity is limited to 7.5 Bcfd, leaving a maximum winter shortfall of 4.3 Bcfd. Monthly-average gas demand for electric generation in winter months (November through February) is 2.1 Bcfd (EIA, 2017). Curtailing all electric generation in favor of core customers, even if this were advisable, would therefore be insufficient to meet peak winter demand. As the remaining demand would still be well above the State's maximum import capacity, gas storage would still be required.

Conclusion 2.15: No method of conserving or supplying electricity—including electricity storage (batteries, pumped hydroelectric, compressed air storage, etc.), new transmission, energy efficiency measures, and demand response—can replace the need for gas to meet the winter peak in the 2020 timeframe. The winter peak is caused by the demand for heat, and heat will continue to be provided by gas, not electricity, in that timeframe. Gas storage is likely to remain a requirement for reliably meeting winter peak demand.

Although changes to the electricity system in the 2020 timeframe will not obviate the need for gas storage in winter, electricity, primarily used for air-conditioning, drives the summer peak in gas demand. Gas-fired electricity demand averages 2,830 MMcfd in August (the highest demand month for gas for electricity over 2011-2016) with a 16-year peak demand of 3,460 MMcfd in July 2006 (EIA, 2017). Modifications that would result in lower gas-fired electricity demand would affect the need for gas storage in the summer.

The potential utility of various changes to the electricity system are described below.

Expanded Electric Transmission Capacity to Reduce Gas Use. Importing more electricity from out-of-state or adding transmission to move more in-state renewables to load centers would displace gas-fired demand by generators in California. In fact, upgrades completed in 2017 are estimated by CAISO to reduce the need for gas -fired generation in the Los Angeles Basin by an estimated 1,000 MW (CAISO, 2016c; CEC, 2017b). Per CAISO, some 56% of the total 74,102 MW of generation in California is gas-fired (Millar, 2017; CAISO, 2017). That gas-fired generation operates at increasingly low load factors. Various generators have threatened to retire their gas-fired facilities because they do not produce enough revenue (RTO Insider, 2016).[100] CAISO can enter into reliability must-run (RMR) contracts if a unit is needed to provide reliability.

100. See also presentations from an April 2017 Joint Agency workshop in the CEC's IEPR to explore the impact of economic retirements. At http://www.energy.ca.gov/2017_energypolicy/documents/2017-04-24_workshop/2017-04-24_presentations.php (Accessed July 2017).

New transmission requires long lead times that extend beyond the 2020 focus of this chapter and come within the planning purview of the CAISO. Like the 2016 upgrades, there may be shorter-term projects that might be completed quickly, as identified in the Renewable Energy Transmission Initiative 2.0 (RETI 2.0). The projects identified in the RETI 2.0 process, MW of deliverability, and total cost are shown in Table 11. Together, they comprise as much as 15,000 MW of electricity that could potentially displace use of natural gas in California at a collective cost of $6.6 billion. Transmission costs would similarly need to be turned into an annual revenue requirement and then spread over assumed usage to arrive at a per kwh cost to consumers. This excludes any new generation that might need to be built.

Table 11. Potential Electricity Transmission Projects.

Resource Area	**Additional Deliverability (GW)**	**Cost ($ 000's)**	**Cost ($000)/MW Deliverability**
Tehachapi*	4.5	$2,100,000	$467
Victorville/Barstow/Riverside	3.7	$34,000	$9
Imperial Valley	1.3	$1,000,000	$754
San Joaquin Valley	1.3	$440,000	$336
Solano	0.9	$35,000	$40
Sacramento Valley	2.1	$3,000,000	$1,429
Lassen/Round Mountain	1.3		
TOTAL	**15**	**$6,609,000**	
Average			**$506**

** - TRTP cost data taken from: https://www.hks.harvard.edu/hepg/Papers/2010/Pizarro_Pedro_HEPG_Feb2010.pdf*

The extent to which additional transmission offsets gas consumption depends on the number of hours the gas-fired power plants would have to run in the absence of the resources carried by that transmission. If 15 GW operates for 8 hours per day,[101] this equates to approximately 0.8 Bcfd of gas load reduction, or about 30% of the calculated 2.8 Bcf needed to meet average summer peak gas requirements. Replacing all of this intrastate capacity to meet summer peak forecasts using electricity imports therefore would require a very large amount of new electricity transmission capability, about 50GW (and associated electricity generation) (CAISO, 2017).[102]

The TransWest Express transmission project from Wyoming to near Las Vegas is an example of the kind of long distance bulk transmission project that might be required. TransWest

101. At an assumed heat rate of 7,000 Btu per kWh.

102. The forecasted 1-in-10 year summer peak for CAISO alone for 2017 was 48,845 MW.

Express will run 730 miles with the ability to deliver 3,000 MW of power. The project will cost about $3 billion. This project has been under design and study for more than 10 years already. Construction might begin in 2018 and be completed by 2020 (TransWest Express). This kind of project represents less than 6% of the 52,000 MW required to replace gas from storage on a summer peak day.

These estimates are only a first analysis. Detailed power system load flow analyses combined with electricity dispatch analysis, would be required to estimate the marginal capability of transmission lines to relieve constraints in specific locations as well as the average heat rate and number of hours the associated new generation would be available and operating and whether this generation is dispatchable in coordination with demand. This first cut also does not estimate how much new generation might need to be built.

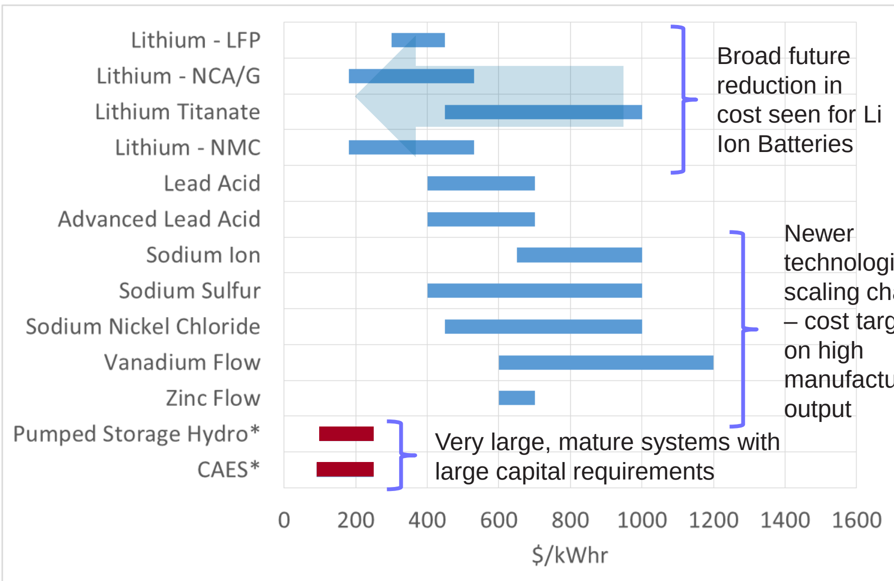
Electricity Storage

Until significant electric-based heating technologies are deployed, electricity storage would play almost no role in mitigating the need for gas storage to meet peak winter demand for gas. However, energy storage could help to reduce the summer peak demand for gas as this demand is driven by electricity generation, albeit at some significant expense.

Electricity storage can reduce summer demand for gas–fired electricity generation up to a point, but there is no type of energy storage we are aware of that can provide electricity storage for more than 48 hours (only a handful of storage facilities worldwide have storage capacities that exceed this). Appendix 3-2 describes various energy storage technologies and their capacities. Energy storage is very expensive compared with gas generation capacity, and even relatively inexpensive technologies such as pumped hydroelectric storage (PHES) and compressed air energy storage (CAES) would be prohibitively expensive to build for several weeks or months of storage capacity. (Moreover, PHES and CAES both have severe siting constraints that limit their widespread use.) For more information, see Energy storage section of Appendix 3-2.

Shorter-time gas balancing requirements, including interday and intraday demand variation, can in principle be handled with various types of energy storage, when the variation in gas demand is primarily driven by electricity generation changes. Electricity storage could reduce the need for gas-fired generation in hours when renewables are insufficient (Kintner-Meyer, 2013). That would offset some of the intraday variability in gas requirements by electric generators that helps drive the need for gas storage, thus addressing part of the electricity ramp-up problem. All storage technologies, including PHES, electromechanical (mainly CAES and flywheel) electrochemical (battery) and thermal storage can provide useful capability in these time domains, though certain technologies, such as batteries and flywheels, are capable of much faster response times and ramping rates than others. However, multi-day electricity demand spikes caused by renewable intermittency may go beyond the capabilities of existing storage technologies.

Figure 22 displays Electric Power Research Institute's most recent cost comparison among some types of energy storage technologies. All systems have capital costs of >$100/kWh of stored energy, with PHES and CAES presenting the lowest costs, and battery technologies being much higher. However, battery costs are projected to fall in cost over the next few years (see Figure 23).



* Pumped Hydro and CAES costs are estimated installed costs; all others are battery costs (not including power conversion or balance of plant)

Figure 22. 2015 Energy Storage Technology Cost Comparison.
Source: Kamath, H., Electric Power Research Institute, 2016.

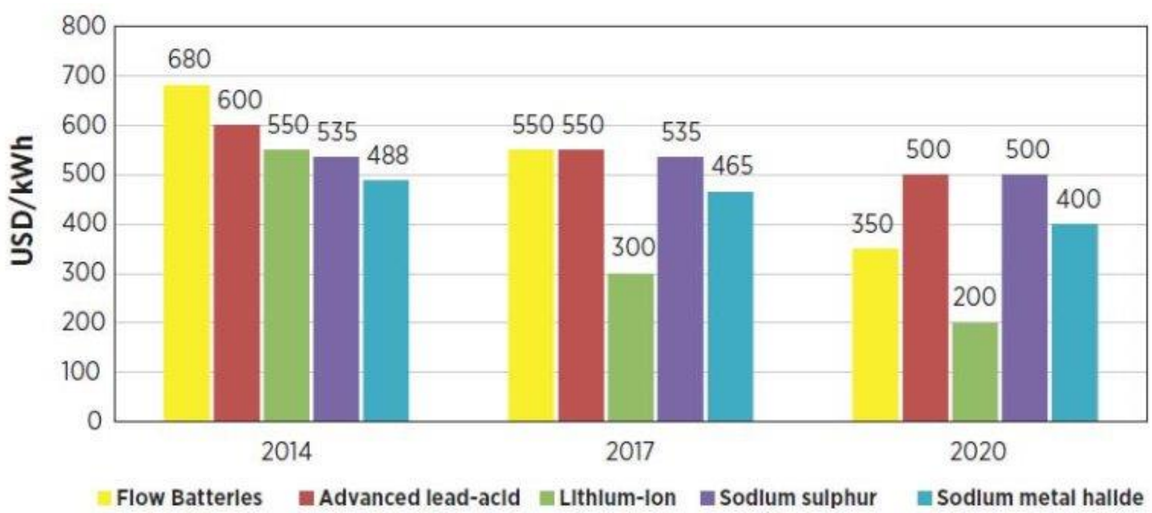


Figure 23. Battery Technology Cost Projections.
Source: AECOM, 2015

The cost of energy storage depends on the duration of the storage required relative to the system's rated power capability. For purposes of cost comparison, we assumed the system requires four hours of energy storage capability. Lazard estimates the cost of a four-hour lithium ion energy storage installation to be between $417 and $949/kWh, or $167-380 million for a 100 MW, 400 MWh system (Lazard, 2016).[103] Assuming each MW of electricity storage offsets use of 7 MMBtu of natural gas per hour in an efficient gas-fired power plant, a system of this size can replace the output of a 100 MW power plant for four hours, and reduce gas demand by 700 MMBtu per hour.[104]

Finding: Meeting all of California's 2,830 MMcfd of unmet summer demand via electricity from energy storage would require approximately 420,000 MWh of electricity storage. Cost estimates for energy storage are evolving rapidly. The current cost of a 420,000 MWh electricity storage system capable of offsetting all gas storage for a peak summer day would be approximately $174 billion at the current low end of Lazard's (2016) cost range estimate ($417/kWh). If costs fall an additional 75%, the cost would be $44 billion to offset the summer peak demand for electricity, but this would do little to address the winter peak driven by demand for gas-fired heat.

Pursuant to current mandates, SCE must procure a total of 580 MW of electricity storage; PG&E 580 MW and SDG&E must procure a total of 165 MW, all by 2020 (CPUC Decision No. 13-10-040). The mandate does not specify how long this amount of power must be provided by storage. Assuming each MW of electricity storage offsets use of 7 MMBtu of natural gas per hour, the total of 1325 MW utility storage mandate can offset 9,275 MMBtu per hour of pipeline or storage withdrawal capacity. This means the current CPUC storage mandate of 1,325 MW of energy storage in one hour could offset roughly 8% of the hourly gas requirement for electricity in the peak summer month that might otherwise need to be pulled from underground gas storage, assuming four hours of storage capacity. To mitigate the entire peak gas demand, about 105,000 MW would be required.

Finding: Current CPUC storage mandates could offset roughly 8% of the peak gas requirement for electricity in the peak summer month (assuming four hours of storage).

Energy Efficiency and Demand Response

Energy efficiency and demand response could reduce the need to withdraw gas from underground storage especially on summer days when the utilities are withdrawing gas

103. It also gives "unsubsidized" levelized costs and breaks out capital versus O&M, for different deployment function scenarios.

104. Note that a 129 MW lithium-ion battery storage project is under construction today in Australia. That project is being constructed by Tesla and Neoen. In addition, a 200 MW battery storage project has been proposed for the Drax power station in Yorkshire, England. The Drax CEO cited the battery's ability to provide "capacity, stability, and essential grid services."

to meet the afternoon electricity generation ramp, but this impact is likely to be small.[105] Energy demand forecasts already incorporate projections of existing and future energy efficiency measures. Those forecasts however, are still in the process of being updated to account for the requirement in SB 350 (De Leon, 2015) to double energy efficiency by 2030. In contrast, it appears that recent estimates of potential demand response are not included in those estimates. The following discusses the tools for demand response in more detail. Demand response is usually called on to deal with peak load and cannot likely displace the routine use of gas storage for intraday gas balancing. The following quantifies natural gas savings through energy efficiency and demand response.

105. The Joint Agency Action Plans for summer 2016 and winter 2016-17 included mitigation measures which, for the first time, rolled out a Flex-Alert type request for core gas consumers to reduce demand on days of gas system stress, in addition to other new programs. EDF criticized the agencies for not achieving greater demand reductions via energy efficiency in a Senate hearing on SB 57 and the County of Los Angeles' consultant cited large reductions achievable via energy efficiency. The reductions they cited turn out to match the energy efficiency estimates shown in the CGR and are already incorporated into the demand forecast used for analysis here.

Energy Efficiency

Developing the forecasts for how much gas would be saved through energy efficiency (EE) starts at the CEC. The CEC develops a demand forecast that includes historical EE from adopted programs, building codes, and appliance standards.

Committed savings (shown in Table 12) are those forecast to be achieved by programs approved by the CPUC and will reduce natural gas demand considerably from what would otherwise be forecast. They include technology measures that have been installed in the past because of utility efficiency programs, building codes, and appliance standards (or those programs that have been funded and have established targets) and these effects are cumulative from their first implementation. As reported in Table 12, committed EE programs were forecast to reduce residential gas demand by 31.2% by 2015 compared to 1975 levels, and 33.3% by 2020. This yields incremental savings of 43 MMcfd for SoCalGas and 30 MMcfd for PG&E, by 2020.[106]

Table 12. Committed Natural Gas Savings.

Year	Committed Savings*	Consumption* (MM therms per year)		Committed Savings (MMcf per day)	
		SoCalGas	PG&E	SoCalGas	PG&E
2015	31.2%	7360	4672	629	399
2016	31.6%	7361	4677	638	405
2017	32.0%	7363	4682	646	411
2018	32.5%	7364	4688	655	417
2019	32.9%	7366	4693	664	423
2020	33.3%	7367	4698	672	429
2021	34.1%	7362	4702	688	439
2022	34.9%	7357	4706	703	450
2023	35.7%	7351	4710	719	461
2024	36.6%	7346	4714	736	472

** Values taken from the 2013 CED 2014-2024 Final Forecast (interpolation used between observed years)*

Source: CEC, 2014b

106. The CEC is developing but has not yet deployed a methodology to forecast electricity demand on an hourly basis. It is unclear if it will also develop a methodology to produce hourly natural gas demands.

The next step adds a second tranche of savings. This is known as additional achievable energy efficiency (AAEE). The forecast of AAEE is created by the CEC based on the Potential & Goals study results, which, in turn, is prepared by the CPUC's consultant (Navigant, 2013).[107] The CPUC and CEC sponsor several meetings among stakeholders to allow input into the Potential & Goals study assumptions and results, including via the CEC's Demand Analysis Working Group (DAWG).[108] AAEE is updated on a cycle intended to be roughly annual and is used both as an input to the California Energy Demand Forecast and by the CPUC in setting investor-owned utility program budgets. The latest AAEE for the electricity sector is shown in Table 13. By 2020, the forecast suggests potential incremental savings of 157 MMcfd if all the electricity-side AAEE directly displaces gas-fired generation.[109]

Energy efficiency by non-electric generation gas demand is also included. Table 14 shows natural gas-related AAEE by 2020 of 16.1 MMcfd for PG&E, 24.5 MMcfd for SoCalGas and 2.8 MMcfd for SDG&E, a total of 43.4 MMcfd. No record of the municipal gas utilities being incorporated into the AAEE could be found and doing so would likely have little impact due to their small total size.

107. See also http://www.cpuc.ca.gov/General.aspx?id=6442452620 The method estimates technical potential, economic potential and market potential. A list of the key parameters and the assumptions surrounding them is provided in Appendix 2-5. The study's five scenarios do not comprise a full Monte-Carlo assessment of the uncertain parameters, but are intended to reflect the range of potential outcomes stakeholders were willing to accept for planning purposes. "Low" cases tend to assume lower penetration of emerging technologies relative to the base case, higher electricity demand and prices, higher incremental measure costs, and conservative assumptions on future codes and standards relative to the base case. "High" AAEE cases have opposing assumptions.

108. DAWG activities are covered at http://dawg.energy.ca.gov.

109. Such an assumption may not be reasonable. The electricity demand should actually be run through an electricity production cost model to determine how generation resources will be dispatched to meet that demand. Such a model will estimate the change in gas demand from a given change in electricity demand.

Table 13. Additional Achievable Energy Efficiency (Electric).

Year	AAEE* (GWh/y)			Marginal Generation** (MMcf/day)				Average Resource Mix*** (MMcf/day)			
	SCE	LADWP	PG&E	SCE	LADWP	PG&E	Total	SCE	LADWP	PG&E	Total
2015	63	286	56	1.6	7.0	1.4	10.0	0.9	4.2	0.8	6.0
2016	875	540	792	21.6	13.3	19.5	54.4	12.9	8.0	11.7	32.6
2017	1812	871	1612	44.7	21.5	39.7	105.9	26.8	12.9	23.8	63.4
2018	2922	1361	2638	72.1	33.6	65.0	170.7	43.2	20.1	39.0	102.2
2019	3742	1770	3366	92.3	43.7	83.0	218.9	55.3	26.1	49.7	131.1
2020	4492	2147	4032	110.8	52.9	99.4	263.1	66.3	31.7	59.6	157.6
2021	5301	2255	4774	130.7	55.6	117.7	304.1	78.3	33.3	70.5	182.1
2022	6077	2363	5484	149.8	58.3	135.2	343.3	89.8	34.9	81.0	205.7
2023	6888	2464	6210	169.8	60.7	153.1	383.7	101.7	36.4	91.7	229.8
2024	7669	2549	6904	189.1	62.9	170.2	422.2	113.3	37.6	102.0	252.9

** - http://www.energy.ca.gov/2015_energypolicy/documents/2016-01-27_additional_aee.php*

*** - this approach assumes that 100% of generation reduced by EE is gas generation*

**** - this approach assumes that 59.9% of generation is from natural gas resources, consistent with CEC values*

Source: CEC, 2017c

Table 14. Additional Achievable Energy Efficiency (Natural Gas).

Year	Savings by Gas Utility (MM Therms/y)				Savings by Gas Utility* (MMcfd)			
	PG&E	SoCalGas	SDG&E	Total	PG&E	SoCalGas	SDG&E	Total
2015	1.8	2.9	0.7	5.4	0.5	0.8	0.2	1.5
2016	11.8	22.7	1.9	36.4	3.2	6.2	0.5	9.9
2017	19.6	40.3	3.1	63.0	5.4	11.0	0.8	17.2
2018	30.7	56.5	5.0	92.2	8.4	15.5	1.4	25.3
2019	44.0	72.8	7.4	124.2	12.1	19.9	2.0	34.0
2020	58.7	89.5	10.1	158.3	16.1	24.5	2.8	43.4
2021	72.1	106.6	12.2	190.9	19.7	29.2	3.4	52.3
2022	85.2	124.2	14.5	223.9	23.3	34.0	4.0	61.3
2023	98.6	142.4	16.6	257.6	27.0	39.0	4.5	70.5
2024	113.5	161.9	18.8	294.2	31.1	44.3	5.1	80.5

** Values taken from the 2015 IEPR Proceedings*

Source: CEC, 2015

AAEE is not adopted as a "point estimate," but is actually a range of values.[110] Figure 24 shows the range of adopted AAEE scenarios. The "mid" case is the CEC's basic reference case. The 2013 Potential and Goals Study describes the approach to estimating AAEE. The AAEE forecast is then turned into EE targets for the gas utilities by the CPUC (Table 15). The latest were adopted in CPUC Decision 15-10-028. These adopted targets include both AAEE and committed savings and are incorporated directly into the gas utility forecasts presented in the California Gas Report (CGR), including the winter peak day forecasts. These EE estimates are clearly lower than the deficit in winter gas requirements that today is met with gas from underground storage.

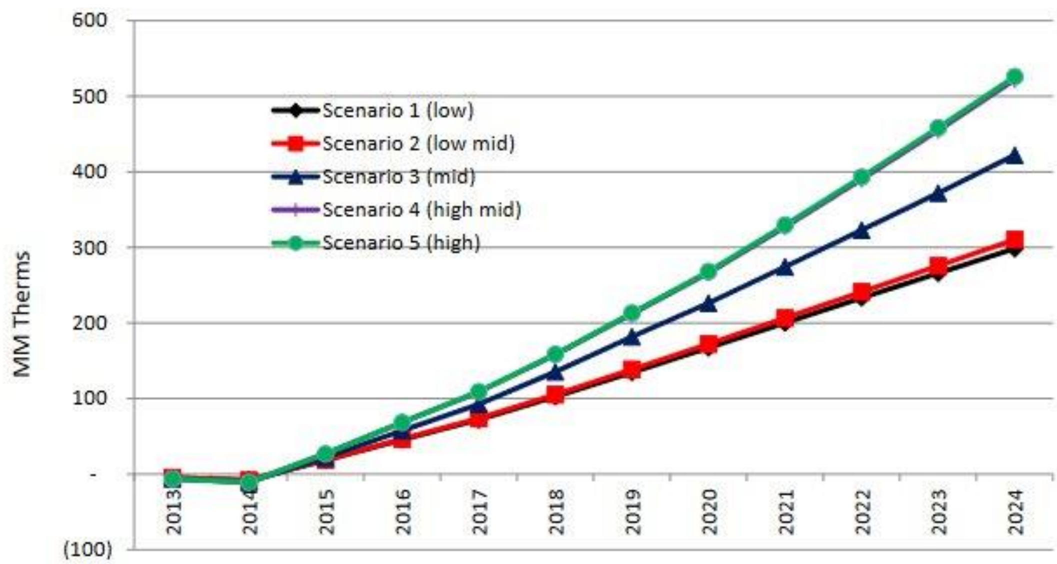


Figure 24. Adopted Natural Gas AAEE.
Source: CEC, 2015

110. The 2013 Potential and Goals Study describes the approach to estimating AAEE. The method estimates technical potential, economic potential and market potential. A list of the key parameters and the assumptions surrounding them is provided in Appendix 2-5. The study's five scenarios do not comprise a full Monte-Carlo assessment of the uncertain parameters, but are intended to reflect the range of potential outcomes stakeholders were willing to accept for planning purposes. "Low" cases tend to assume lower penetration of emerging technologies relative to the base case, higher electricity demand and prices, higher incremental measure costs, and conservative assumptions on future codes and standards relative to the base case. "High" AAEE cases have opposing assumptions.

Table 15. CPUC Adopted Targets for Gas Utility Energy Efficiency.

Year	PG&E		SoCalGas		SDG&E	
	Annual (MM therms/y)	Daily (MMcf/day)	Annual (MM therms/y)	Daily (MMcf/day)	Annual (MM therms/y)	Daily (MMcf/day)
2016	18.4	5.0	29.1	8.0	3.2	0.9
2017	18.6	5.1	30.3	8.3	3.3	0.9
2018	20.9	5.7	29.4	8.1	3.9	1.1
2019	21.1	5.8	30.6	8.4	3.9	1.1
2020	21.7	5.9	30.6	8.4	4.0	1.1
2021	21.8	6.0	28.6	7.8	3.7	1.0
2022	22.4	6.1	28.5	7.8	3.7	1.0
2023	23.2	6.4	28.2	7.7	3.8	1.0
2024	23.9	6.5	28.1	7.7	3.8	1.0

Source: CPUC, 2015e

These estimates do not yet reflect the full effects of SB 350 (De Leon, Chapter 547, Statues of 2015) which requires a "doubling" of cumulative statewide EE based on the mid-case estimate of AAEE adopted in the California Energy Demand Forecast Update 2015 – 2025 by 2030. PG&E estimated in the 2016 CGR that a simple interpretation of the bill (without regard to cost-effectiveness) represents an increase of 600 million therms above current EE levels by 2030 which they say equates to 156 MMcf per day. If achieved every day, this could free up the need to meet that same demand with gas from storage, a relatively small portion of California's 4.3 Bcfd shortage on a peak day.

Finding: Energy efficiency measures including the combination of committed savings for natural gas, combined with the reductions expected from AAEE (ignoring the uncertainty in its calculation) and the doubling required under SB 350, appear to total less than 400 MMcfd (assuming all of the electric side savings reduce the need for gas-fired generation). If achieved every day, this could remove the need to meet that same demand with gas from storage, but comes nowhere near offsetting California's 4.3 Bcfd shortage on a winter peak day or any other winter day. The actual impact would depend exactly which measures are adopted, what technologies are affected, and what the hourly use pattern changes are.

Demand Response Gas Savings

While the EE estimates appear to have already been incorporated into the demand forecasts, there appears to be some potential to reduce gas demand through demand response (DR) measures that are incremental to forecasted values. Demand response potential is incorporated into electricity demand forecasts to the extent that demand response measures are load modifying. On a statewide basis, only 140 to 220 MW of load-modifying demand response potential is included in the CEC electricity demand forecasts, used by CAISO for transmission planning work and the CPUC for procurement decisions (CEC, 2016a).

The CPUC commissioned LBNL to estimate demand response potential. The Phase 2 report released in March 2017 shows system-wide potentials for fast demand response totaling 5,600 MW in 2020 and 7,300 MW by 2025. These totals are shown in Table 16. Converting this to a gas capacity requirement requires assuming a heat rate for the associated generation. It also requires assuming not only the number of hours the generation would operate but assuring the gas delivery capacity is available in every hour. Table 17 shows this two-step conversion of the potential demand response to their corresponding gas pipeline capacity reduction impact, using the same power plant heat rate of 7 MMBtu per MWh as earlier. Reducing the summer system peak by 5,600 MW translates to a gas demand reduction and the need for more than 900 MMcfd of gas pipeline capacity. If less efficient power plants were the ones displaced on peak, then the pipeline capacity reduction would be correspondingly higher.

Figure 11 shows about a 1 Bcf increase in the flow rate needed over the course of the day for SoCalGas on September 9, 2015. That equates to an increase of about 42 MMcf per hour in gas demand. The 2020 estimate of DR for southern California is ~23 MMcf per hour, implying that DR could offset more than 50% of the increase in hourly demand caused by electricity generation in afternoon hours). DR, however, by its very nature cannot be called upon every day.

Table 16. Electricity Demand Response Potential.

Year	Electric DR Potential (MW)					
	PG&E	SCE	SDG&E	LA System Peak[13]	LA IRP*	Total
2020	2300	2400	170	599	175	5644
2025	2900	2900	260	724	475	7259

13 This method applies the demand response/system peak ratio of SCE to LADWP.

Source: LBNL, Aspen Environmental Group, and Alstone, et al., 2017

*LADWP, 2016

Table 17. Gas Pipeline Capacity Reduction from Electric DR.

	MMcf per hour						MMcf per day					
Year	**PG&E**	**SCE**	**SDG&E**	**LA System Peak**	**LA IRP**	**Total**	**PG&E**	**SCE**	**SDG&E**	**LA System Peak**	**LA IRP**	**Total**
2020	15.6	16.2	1.1	4.1	1.2	38.2	373	390	28	97	28	916
2025	19.6	19.6	1.8	4.9	3.2	49.1	471	471	42	118	77	1,178

Source: Aspen Environmental Group

In conjunction with the May 22, 2017 Joint Agency workshop to discuss summer 2017 reliability risk, the CPUC released estimates that customers achieved 1.68 MMcfd of 2016 summer DR (largely through electricity programs) and that “marketing and outreach” accounted for an additional 12.5 MMcfd. Marketing and outreach includes Flex Alerts, press conferences, and news coverage. Those estimates are more fully detailed in a separate CPUC staff report, where they are broken out by specific program (CPUC, 2017d). The LBNL DR study, however, suggests significant impacts, based on the medium DR scenario. However, DR (by definition) is something to be used relatively infrequently and cannot routinely reduce peak hourly gas demand during summer days. Table 18 provides summary comments for each of the supply and demand options evaluated in this section.

Finding: The demand response potential appears large enough to offset a good portion of the withdrawal from storage needed to support intraday load balancing by electricity generators but demand response cannot be called upon routinely enough to fully replace the need to use gas from underground storage.

Table 18. Supply and Demand Options to Replace Gas Storage (Assuming No Outages on Gas System and No Forecast Error). [111]

Physical Alternatives to Storage	**Rough Cost Estimate ($2017)**	**Summary Comments**
Alternatives that could completely offset the need for 4.3 Bcfd gas storage in winter		
New Intrastate Pipeline Capacity	~$15 Billion	• Not achievable by 2020 • Maybe one or two pipelines by 2025 • As peak demand declines the needed expansion quantity would also decline • Addresses winter but probably not intraday needs • May pose siting issues to reach load centers • Requires environmental review and mitigation
LNG Peak Shavers	~$10 Billion	• Depending on size, could require 4 to 10 units • Unclear effectiveness to load follow during the gas day • Conversion from gas to LNG and back requires energy that would increase GHG and criteria pollutant emissions • Poses siting and safety concerns
Alternatives that could reduce the need for gas storage somewhat		
LNG Via Ocean Terminal	$332 million per year incremental cost to purchase 315 MMcfd of LNG	• Use of Sempra's Costa Azul to serve SDG&E (an average of 315 MMcfd) appears immediately feasible • Would allow pipeline supply to serve LA, reducing need to pull gas from storage for LA. • Not clear if reduction in withdrawals from storage in LA is 1:1 with gas demand on all days but at least 200 MMcfd (~5%) seems reasonable to consistently expect • Increases GHG and criteria pollutant emissions from LNG transport and vaporization
Alternatives that will have little impact on winter gas storage requirements		
New Electric Transmission Capacity to Reduce EG Gas Use	$6.6 Billion identified in RETI 2.0 that could deliver 15,100 MW	• 15,100 MW is equivalent to 800 MMcfd or 27.5% of the 2.9 Bcf needed on an average gas summer peak day, so this transmission doesn't offset entire summer peak demand • Would not address the winter peak because winter peak is caused by burning gas for heat • Wouldn't address intraday gas balancing need
Containerized LNG	Infrastructure cost of $13 million for 1 Bcf per year plus 440 containers (Hawaii Public Utilities Commission, 2014).	• Not Utility-Scale (10 Containers per MW) but may have limited application for intraday balancing at power plants • Poses additional siting and safety risks plus emissions with conversion from gas to LNG and vice versa

111. Note that all of the discussion on the quantity of storage needed assumes no outages on gas system and no forecast error.

Physical Alternatives to Storage	**Rough Cost Estimate ($2017)**	**Summary Comments**
CNG In a Box	$600,000 for ~2 MMcfd, so 500 MMcfd (for example) amounts to $150 million (excludes pipeline interconnection costs). 8000 containers would cost $4.8 billion.	• Not Utility-Scale but may have limited application for intraday balancing at power plants • Requires many containers and poses additional siting and safety risks • Takes a whole day to compress and fill container
Electricity Storage	$273 million for each 100 MW/4-hr system	• Can address intraday balancing with 4- and 8- hour storage, but cannot address winter gas requirements
Diesel Fuel	Assuming CARB-standard diesel @$3.00 per gallon and 7.2 gallons per MMBtu = $21.6 per MMBtu	• Not desirable for AQ reasons and would need to reinstall handling and on-site storage equipment largely removed in 1990s • Amber 360 is "cleaner" but even if enough were produced and available, need to address the generator warranty void
Renewable Natural Gas and Power-to-Gas	~$30 million to process about 100 MMcfd to pipeline quality plus up to $3 million per interconnection. Hydrogen Business Council says P2G would be 2.5X current natural gas price by 2030.	• Not available at scale by 2020 and production profile does not help solve gas storage problem.
Energy Efficiency (EE) and Demand Response (DR)	EE is required under statute so will be a sunk cost	• EE is already in the demand forecast • Gas utilities suggest a gross read of the SB 350 requirement to double EE by 2030 implies an additional reduction of 156 MMcfd ignoring cost-effectiveness • Additional potential electricity DR could reduce the need for intraday balancing • Implementation would require examination of how often that DR could be used • DR used to curtail electric generation in favor of core customers would be insufficient to meet peak winter demand • Statewide gas import capacity is limited to 7,511 MMcfd. Monthly-average gas demand for EG in winter months is ~2,000 MMcfd • The highest recorded total gas demand (EG + non-EG) in the recent five-year period was 11,157 MMcfd (December 9, 2013) • Curtailing all EG would subtract 2,200 MMcfd of demand from this day, but this is still well above the State's maximum import capacity - e.g., gas storage would still be required

Conclusion 2.16: We could not identify a technical alternative gas supply system that would meet the 11.8 Bcfd extreme winter peak day demand forecast and allow California to eliminate all underground gas storage by 2020. Two possible longer-range physical solutions are extremely expensive, carry their own risks, and would incur barriers to siting. The potential benefits of other approaches that were examined are either small, cannot be estimated at this time, or have negative impacts such as dramatic increase in air toxins and greenhouse gas emissions. No “silver bullet” can replace underground gas storage in the 2020 timeframe.

1.4.2 Regulatory and Operational Options (Including Market Rules) to Help Replace Underground Gas Storage

Regulatory or operational changes may help reduce the need for underground gas storage. This section evaluates proposed or already implemented changes to gas market regulation from two perspectives (1) the degree to which they can reduce or eliminate the winter peak demand problem and (2) the degree to which they can reduce the need for natural gas storage at other times during the year.

This subsection considers eight potential changes. Some of these are already being implemented as mitigation measures to help reduce the risk of electricity outages stemming from the limited availability of Aliso Canyon. They include:

- Tighter Balancing Rules
- Core Customers Balancing to Load Instead of Forecast
- Greater Use of Line Pack
- Closer Gas-Electric Coordination
- Shifting to Out-of-Area Generation on Gas-Challenged Days
- Day-Ahead Limits on Gas Burn
- Shaped Nominations and Flexible Services
- Weekend Natural Gas Market

Tighter Balancing Rules. Tighter balancing rules could reduce the winter peak demand somewhat and reduce the need for storage at other times. System imbalances are differences between supply and demand that can be caused by customers’ scheduling less gas for delivery than their actual usage. The technical assessment group that prepared the analysis underlying the Joint Agency mitigation measures for summer 2016 identified that system imbalances as small as 150 MMcfd could require SoCalGas to pull gas from Aliso Canyon.

Based on this, the technical assessment group recommended tightening the balancing rules for non-core customers. The agencies also asked SoCalGas to prepare a hydraulic analysis to determine the impact of keeping receipts and demand within 5% of each other. The analysis showed that balancing non-core load to within 5% improved operating pressures by enough to reduce the risk of curtailment to customer load
(CPUC, 2016d).

Many customers (including generators) objected to the imposition of daily balancing. They and SoCalGas ultimately settled, agreeing that SoCalGas could make greater use of its relatively new authority to declare daily operational flow orders (OFOs) for low pressure, and that SoCalGas could simultaneously call an OFO for high pressure. Essentially, this allows SoCalGas to require daily balancing for a single day at a time instead of making the tighter balancing requirement a standing one that applies to every day. The CPUC approved this settlement in Decision No. 16-06-021 and extended it in Decision No. 16-12-015.

A standing rule to balance every day does not allow customers any room for error in matching supply and demand. Storage is essential to allowing flexibility. Pipelines that do not have storage allow very little flexibility. If California did not have underground gas storage, the State likely would never have allowed balancing provisions to be so liberal. Should storage be reduced and consequently system slack reduced, regulators will undoubtedly have to consider tighter balancing rules.

Core Balancing. As discussed previously, the utilities' core procurement groups must balance their loads, but they do not have to balance to actual load like non-core customers do. Rather, they balance to their forecast of core load. The current rule allows core to be deemed in balance even when there is a large difference between forecast and actual load. Misforecasting core load can result in a system imbalance that must be cured with gas from storage. Non-core customers recommended, in SoCalGas' triennial cost allocation proceeding (TCAP), that the utility be required to balance core load to actual load instead of only the forecasted load. The difference between forecast and actual load, especially in the winter months, can be large enough to necessitate use of underground gas storage even when the non-core load is perfectly in balance. Allowing core to balance to an erroneous forecast essentially gives core more liberal balancing rules than non-core, leaving non-core customers bearing the brunt of insufficient storage availability to buffer imbalances.

Essentially, the system accommodates forecasting errors on the part of core customers. Arguably, both PG&E and SoCalGas could improve their daily core load forecasts since they have years of intimate, direct experience developing the forecast and managing core demand. From their experience, they know which core customers on which parts of their system are more or less weather-sensitive than others and how weather variation affects demand. They also know how often they miss their own daily load forecast and the reasons for forecast errors.[112] Neither PG&E nor SoCalGas are currently obligated to balance core load to their day-ahead forecasts, nor do they reveal how different their forecast is from actual core load. Non-core customers have argued that the installation of smart meters should allow for improvements in forecasting core load such that this change should be feasible. The settlement agreement in SoCalGas' TCAP, Decision No. 16-12-015, required SoCalGas to file an application "to address the feasibility of incorporating [smart meter] data into the core balancing process," including testimony regarding costs and technical issues. They filed their application on October 2, 2017 (SDG&E, 2017; SoCalGas, 2015). No similar order applies at this time to PG&E but its upcoming Gas Transmission & Storage rate case.

Tackling this issue may require understanding daily core load forecasting and how to narrow its associated range of error and imprecision. Success would undoubtedly require a change of mindset and possibly incentives for the utility to be more precise and not use slack in the system to make up for lack of precision in the forecast. This precision around daily core load forecasting would be new territory for the California gas utilities, but any reduction in imbalances reduces the need to use gas storage. Without data from utilities on their core load forecast errors, quantifying potential benefits of this strategy is not possible.

Greater Use of Line pack. Greater use of the line pack essentially means operating the gas system at higher pressures to compress more natural gas into the pipelines for use during high demand periods. Greater use of line pack would not obviate the problem of meeting peak winter demand nor would it have much impact on other uses for storage.

As explained earlier, line pack is the gas in a transmission pipeline or distribution main that keeps the line pressurized. Linepack must be sufficient to allow customers to take gas out of the pipeline without pressures dropping so low that gas stops flowing. The fact that gas is compressible allows gas molecules to be packed closer together, pushing more gas in to occupy a given segment of pipeline. On the high end, the safe maximum allowable operating pressure of a line limits the amount of line pack. On the low end, line pack must maintain the sufficient pressure differential between inlet and outlet points required for gas to move.

Gas distribution companies routinely use the line pack of their pipelines as temporary storage by "packing" the gas in their lines overnight and drawing the pack down first thing in the morning when demand peaks. This ensures a "full" pipeline as the new gas day starts, and leaves enough gas in the system after the peak to help meet demand over the rest of

112. These daily forecasts are updated using more precise short-term (sometimes day-ahead) weather forecasts very close to the time of gas delivery and are not the same as the longer-term, weather standards used for system planning and cost allocation.

the day. Packing prevents low gas pressure and outages that would otherwise occur during hours of the day when natural gas use is heavier, given that supply comes in at a flat rate, the same each hour. In this way line pack helps accommodate short lived, relatively small, and relatively predictable imbalances between demand and supply in certain hours of the day.

First, the natural pull of supply and demand will result in limited potential to use pipelines as storage beyond the current use of line pack in its diurnal pattern (gas always moves towards the lower pressure or open valve). The packed gas would flow downstream unless the transmission system is "shut in" to keep all of the packed gas within the transmission system.

Second, a gas distribution company would need to continuously pack the gas network, not just overnight as one does now, but in every hour with demand lower than the peak hour. Doing this can mean that the amount of gas in the pipelines would at times exceed the amount needed to meet demand and this condition may cause adverse operational issues. For example, if demand to use the increased line pack did not materialize, the operator would be faced with potentially unsafe operating pressures and have to find a way to release the excess gas. Expanding the use of line pack to replace California's underground gas storage would trade risks associated with storage for risks associated with higher pressure use of pipelines and may violate best practices and safety norms.

Another issue may be that contractual gas day amounts may limit the amount of gas that can be "packed" in the transmission pipeline system; someone would need to provide more gas for packing into the line. Gas distributors and pipelines do require customers to deliver gas for "shrinkage" (i.e., gas used to run compressors and gas that is lost in measurement discrepancies); if the gas company has room in its system to accommodate some increase in the standard percentage above expected demand that all customers deliver, the action would represent an increase in the cost of gas that all customers would pay in order to buy and deliver more gas to the distribution company every day.

Another constraint is posed by the fact that there are likely not enough hours after the morning peak occurs to repack the lines to meet the afternoon and early evening peaks without using gas from underground storage. Figures 21 and 22 show the result of a 1,700 MMcfd change in demand between 6am and 6pm. This led to a 150 psig change in pressure on SoCalGas' northern system and a constant 75 psig drop they found unacceptable on their lower pressured LA Basin system measurements at El Segundo and Los Alamitos. This pressure drop occurred with maximum withdrawals from three storage fields (while Aliso Canyon was unavailable). SoCalGas claims to use all its pack and draft ability in a given operating day to help balance its system (Shell Energy North America, 2009). Their hydraulic simulations are constrained to restore the system line pack. In other words, if the operators in Gas Control sees pressures dropping within a gas day such that it is not sure it can restore line pack overnight, it will curtail non-core load to preserve system integrity to serve core load.

Similar hydraulic results for PG&E are not available in the public domain. PG&E may have much more line pack than SoCalGas, owing to the longer distance of its transmission lines from the receipt points to its load centers. The distance from Malin and Topock to Antioch (near McDonald Island) is 356 and 545 miles, respectively, while the distance from Topock and Ehrenberg to LA is 275 and 227, respectively. SoCalGas doesn't report line pack, or the status of hourly operating pressures that indicate whether its system is in a pack versus draft condition, but PG&E does. The CPUC reviewed the differences between the pack and draft capabilities of the two systems in response to requests to change the balancing rules and switch to an operational flow order regime for SoCalGas in 2014. The result was a finding that SoCalGas often runs its line pack from minimum to maximum levels within a gas day and that there is no additional line pack capability available for gas operations (CPUC, 2015a).[113]

PG&E, on the other hand, has about 650 MMcfd of line pack (see Figure 25) and calculates the need for OFOs based on its daily pack versus draft conditions, or how much line pack remains, and projects its rise and fall over the work week. Typically, gas supply is relatively flat over the week, but demand is lower on weekends. PG&E's line pack therefore tends to become increasingly depleted as the week progresses and then recovers over the weekend with the natural ebb and flow of weekday versus weekend demand. Typically, within a day the system recovers line pack at night before the following gas day begins. When pipeline inventory deviates from these boundaries, PG&E calls OFO's asking customers to eliminate their imbalances to bring inventory back into its acceptable range. SoCalGas, in contrast, focuses its OFO calculations and protocols solely around the difference between receipts and demand (and nominations to withdraw from storage) every single day.

113. See also Finding of Fact 26: "Applicants' (referring to both SoCalGas and SDG&E) system lacks sufficient pack and draft capability to provide balancing services by way of line pack." On PG&E having more line pack than SoCalGas, see Finding of Fact 23.

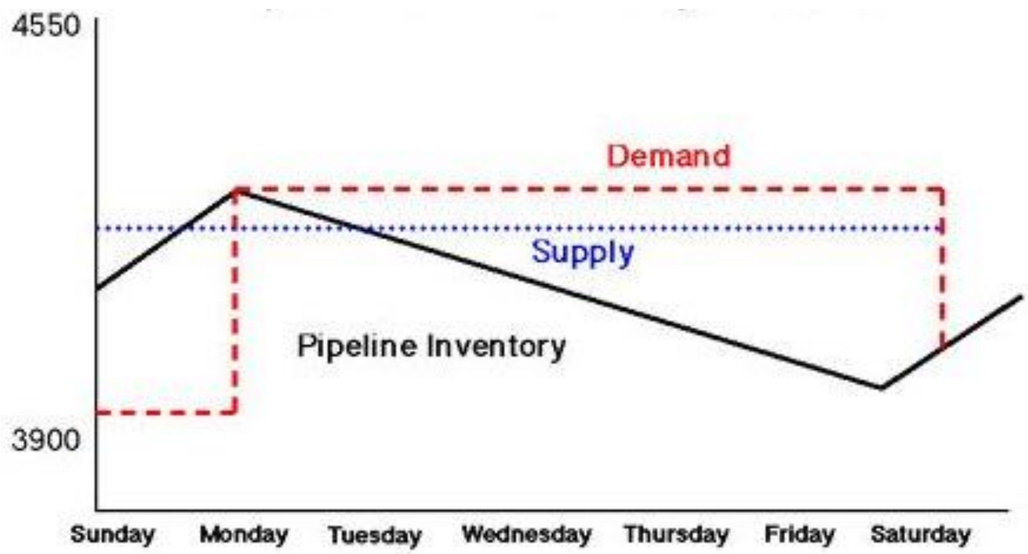


Figure 25. Illustration of PG&E Pipeline Inventory Linepack Variation During the Week. Source: PG&E Pipe Ranger, n.d.

Verifying the utilities' stated line pack limits would require detailed work using hydraulic network modeling software and detailed specifics. Such modeling would elucidate the intricate relationship between line pack, efficiency, supply, and demand on the network to determine to what extent line pack gas can be "stored" in the pipeline while the system is in use. Such modeling cannot be done without obtaining and using the detailed data from the utilities not currently available in the public domain. The information available suggests it does not seem physically practical to simply increase reliance on line pack as a way of meeting the larger imbalances on PG&E or SoCalGas.

A dedicated piece of pipe can consistently store gas similar to a storage field (FERC, 2011).[114] It may be possible in specific situations to add additional pipeline segments near power plants and potentially loop them in with the existing segments, or simply replace a segment with larger diameter pipe. This additional space might be allowed to hold extra line pack. The operational caveats from above apply: the segment would need to be valved off so that the line pack cannot migrate to lower-pressured parts of the local transmission or distribution system; it takes a radically different gas system configuration to pull this off.

114. The nearly 1,000-mile EPNG system has perhaps 1 Bcf per day of line pack (supporting a prior point that longer systems tend to have more line pack) and still requires customers to remain in balance.

ICF International explored the idea of adding pipeline segments near power plants to some degree in the 2011 study, “Integrating Variable Renewable Electric Power Generators and the Natural Gas Infrastructure,” in which they illustrated the benefit of expanding a lateral pipeline from 10” to 14” (off a 16” 83-mile mainline) to serve a 100 MW combustion turbine. ICF expected the turbine’s gas requirement would increase from 100 MMcfd to 180 MMcfd in response to decreases in output from a nearby wind farm, ostensibly an example of renewable generation’s intermittency. That increase in gas requirement could cause the gas inlet pressure to the turbine to drop enough to trip the unit off. ICF found that increasing the pipeline diameter by 4” would increase gas supply within the lateral pipeline by 3 MMcf and reduce the pressure drops occurring at the combustion turbine.[115] It is not clear, however, that the line pack would be sufficient to provide the entire hourly gas requirement of the power plant.

ICF performed another study for the Interstate Natural Gas Association of America (INGAA) Foundation, “Firming Renewable Electric Power Generators: Opportunities and Challenges for Natural Gas Pipelines” (INGAA, 2011). Here ICF analyzed the impact on both line pack and operating pressures in additional scenarios using transient hydraulic modeling. They found that shorter nomination cycles helped stabilize line pack somewhat but did not conclude whether the line pack would be sufficient to supply the plant’s higher gas demand (ICF International, 2009) or the ability of the gas system to use line pack to supply the ramp requirement over all hours required. ICF did note the importance of underground gas storage as a system “shock absorber.”

Finding: Utilities and pipeline companies already use the line pack they have available. Using line pack beyond the normal operational ranges in use today creates a safety concern because a section of overfilled pipe could lead to over-pressurization and potential release of gas.

Closer Gas-Electric Coordination. The goal of operating with less gas storage has led to focus on operating with tighter margins by increasing coordination between the natural gas and electricity systems to thereby reduce unnamed inefficiencies that would in turn result in needing less gas from storage. Gas-electric coordination aims to reduce reliance on physical storage to make up for unplanned deviations between generation needs and gas availability. Such coordination might reduce the winter peak demand, but quantification of this will require further study including hourly dispatch modeling rather than planning models. Coordination will also help with other uses of storage.

115. This scenario is also remedied by installing a compressor at the compressor turbine; many of the independent generators funded via nonrecourse financing installed their own compressors and in some cases doing so was a condition of financing.

Project GECO, an ARRPA-E project led by Newton Energy Group and Los Alamos National Laboratory suggest that gas and electric demand can or should be co-optimized. Economic theory certainly suggests that hourly natural gas prices and hourly nominating periods, would cause greater optimization of the two systems by virtue of delivering more accurate price signals during those key hours in which natural gas is of higher value owing to higher demand. Reductions in physical storage would increase the variability of the value of storage between hours. Price signals to reduce natural gas use could also help preserve electric reliability.

California's balancing authorities have already made improvements in coordinating actions. Operating room personnel talk to each other almost daily; and, during times of system stress, they may talk to each other multiple times per day.[116] They hold table-top exercises and conduct analyses of how much gas use could be reduced by reorganizing the electricity system dispatch and the limits of doing so. They schedule maintenance during low demand periods and move generation to alternate plants. These actions were spurred by the February 2011 southwest cold spell, discussed previously herein. All these efforts were expanded with the constrained operations at Aliso Canyon. Some of the specific coordinating changes recommended in the Aliso-related joint agency reliability action plan required changes to CAISO's tariff. These and a description of related actions are described in Appendix 2-7.

Nevertheless, these efforts do not constitute an hourly or sub-hourly economic co-optimization to reflect the time-value of gas. Similar processes were used in the past to schedule power plant dispatch but were not as effective as the use of modern organized wholesale market optimization algorithms.

A broader effort to promote coordination seems unlikely to succeed given the effort expended since 2012 with the open FERC rulemakings and NAESB discussions. Specific coordination efforts such as those requested by CAISO in response to Aliso Canyon are arguably more likely to be tractable enough to produce useful results. However, even with all of the above coordination actions – and when only Aliso Canyon service operations are constrained – the system operators remain concerned there will be days when we need more gas than we can get from storage.

Shifting to Out of Area Generation On Gas-Challenged Days. Not having gas storage will increase the frequency at which the gas system cannot meet all demand at assumed weather conditions (see Figures 16 and 17). In the 2016 summer and winter risk assessment

116. A pre-Aliso summary of CAISO gas-electric coordination activities by the CAISO's Director of Regional Operations Initiatives is available from a November 2014 CEC workshop on the subject. Found at https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=15-IEPR-04 "NG Electricity Coordination and Effects on NG System CAISO Brad Bouillon" (2014a; accessed May 2017).

technical reports (and now summer 2017, too) CAISO documented some ability to shift generation to plants located outside the LA basin and some outside the SoCalGas service area on gas-challenged days. The ability to shift generation was smaller in the summer than in the winter because the summer had higher electricity demand resulting in higher loading of the transmission lines and more plants in operation. This meant most plants were already operating and being dispatched which left fewer alternatives to shift towards. In winter, their analysis found lower loads, which meant fewer plants were operating, transmission import lines were less loaded, and greater imports were feasible to replace generation from plants located in or near the LA Basin. The conclusions were reached through power load flow analysis (such as with GE's positive system load flow platform) used to test loading of transmission lines as electric generation is shifted away from gas pipeline systems facing gas constraints. Then by performing a dispatch analysis (as with production cost model) to determine how many hours the replacement plants must run to meet all electricity demand and satisfy NERC reliability requirements.

No similar analysis is available for generators who receive natural gas from PG&E. Moreover, the specific modeling results remain confidential due to FERC rules to protect market quality and prevent market manipulation. That being said, in the southern California analysis, the shift in generation logically would have been to units that are served from pipelines, such as Kern River instead of by SoCalGas.

To the extent that generation is shifted, three negative consequences occur. First, the "go to" plants represent a second-best solution from an economic efficiency perspective, otherwise they would not be available to operate in lieu of the first-best set of plants.
This uneconomic dispatch that results from not using the most efficient generating units to produce electricity means electricity production costs, and thus costs to consumers, will increase. The second negative consequence is that using less efficient generators means the overall quantity of gas burned will be higher (though it will be in places where the gas is accessible). The third negative consequence is that burning more gas in less efficient plants means the emissions of greenhouse gases and criteria pollutants will be higher.

The fact that CAISO's analysis suggests other generators can replace the local gas-fired generation does not guarantee that shifting will be feasible on the day needed. Rather, their analysis is a planning analysis; in real-time, the ability to shift generation will depend on which plants have forced or unforced outages on the day in need. The analysis also assumed there were no electricity transmission outages affecting the ability to replace some of the generation with imports, or to get it from the substitute units into the load centers and that gas was in fact available to those other plants. The latter assumption may be particularly optimistic on very cold days that affect not only California demand but demand located between California and producing areas, supply deliverable to California, or regional price differentials that cause suppliers to prefer sales to markets other than California.

Finding: Opportunities to shift to out of area generation on gas-challenged days are limited and not reliable.

Day-ahead limits on gas burn. Beginning summer 2016, CAISO, with approval from FERC, implemented a procedure giving themselves the authority to give burn limits to individual generators. Using this authority, CAISO can direct gas to specific units needing generation in order to avoid electricity blackouts, regardless of economic dispatch. LADWP implemented a somewhat similar procedure in which it fixed its gas burn quantity, nominated that quantity, and then met any shift in requirements with other resources. By specifying and limiting the gas burn day-ahead, the electricity system essentially sets a maximum on its gas nomination for the next day and seeks to avoid going "over" the maximum quantity the gas system can deliver on the next day. In essence, via these measures, the gas system now limits the electricity system.

This helps in the context of not having full output available from Aliso Canyon and was intended as a short-term measure. If there was no gas storage in California, the balancing authorities might instead propose that they calculate a minimum gas need and design the gas system around how to deliver it.

Finding: The technical assessments for the Aliso Canyon Reliability Action Plans indicate day ahead limits would be helpful, but not a full solution for the winter peak demand. It cannot, for example, eliminate error in the weather forecast.

Shaped nominations and Flexible Services. Natural gas wells, absent problems, produce gas on a flat hourly basis over the course of a day. Some of the difference between production and demand goes into storage in facilities near producing areas. Figure 2 showed the relative locations of gas storage fields across the U.S.; much of the storage in Texas, Oklahoma, Kansas, or Louisiana would be considered "production area storage," whereas the storage in California is considered "market area storage." Some work is going into the idea of allowing gas nominations to vary over the course of a gas day, whereas today they are fixed (consistent with production patterns). If gas could flow into California on a shaped basis within the gas day, the need for gas storage to support intra-day balancing would be reduced.

Canadian producers might be able to use the AECO-C™ commercial natural gas storage hub in Alberta to support shaped nominations on the GTN pipeline to some degree. Kern River might be able to allow some amount of shaped nominations if the Magnum storage project proceeds.[117] In both cases, that possibility may depend on how much of the storage capacity

117. Magnum is to consist of 4 solution-mined storage caverns capable of storing 54 billion cubic feet (Bcf) of natural gas, for three to four turns per year and with peak injection of up to 360 MMcfd and withdrawal of up to 500 MMcfd. It will be connected to Kern River via a newly constructed 61-mile-long header pipeline. See http://westernenergyhub.com/pdf/Magnum-Gas-Midstream_Open-Season-Press-Release.pdf (Accessed April 2017). FERC approved Magnum's request to slightly alter the geographic location of its facilities and for market-based rates in November 2016, and has since approved Magnum's request of an extension of time to July 2017 to file its construction compliance plan. Magnum estimates 3.5 years from granting of the CPCN to completing construction and being available to provide service. See FERC Dockets CP10-22-000 and CP16-18-000.

the pipeline itself controls. The shaped nominations would still need to match the hourly load shape, and storage located several hundred miles away would be unable to respond to short-notice changes, making this solution insufficient for all situations. Appendix 2-8 describes experience with flexible nominations in other states.

Finding: If California had no underground gas storage to support shaped nominations, storage somewhere upstream would be required to support the variation in load. However, this remote storage would be unable to respond to short-notice changes.

A gas system without underground gas storage might require costs to be reallocated such that they more accurately reflect use of the system. The cost allocation principles adopted in the 1986 initial unbundling order and later amplified in the 1992 gas marginal cost decision focus on "cold year throughput" and winter peak demand (CPUC Decision Nos. 86-12-009 and 92-12-058). A system without storage or with less storage may need an allocation that more accurately fits actual use of the system, and particularly, monthly or hourly use of the system. As the electric system moves to Time of Use rates in order to send more accurate price signals, a gas system without storage might need something similar. More precise price signals, in theory, should reduce peak usage.

California also seems to have reached a point at which we are no longer willing to allow electric generation or refineries and other key non-core users to bear gas curtailments.[118] If that is so, then the old framework in which most costs were allocated to core customers with non-core customers getting lower rates to fill in the gaps when the pipeline is less used no longer matches our policy desire to essentially give these generators and refineries firm service.

Weekend gas market. A weekend gas market could help to reduce, but not eliminate the need for storage. The electricity market operates 24/7, but natural gas is transacted in less than eight hours a day. Once the market stops trading (around noon East Standard Time) for tomorrow's business, it becomes not only thinner in terms of uncommitted volumes available but in terms of bodies at a desk available to suppliers. Customers with smaller loads may have a problem finding a supplier available, and even a significant user like LADWP has indicated difficulty. California cannot by fiat require gas suppliers to be available after the timely nomination window. It can, however, encourage in-state participants to the NAES Board gas quadrant discussion to support 24-hour markets. (It is also possible that tighter markets without storage in California would induce marketers

118. See for example letter from CEC Chair Robert B. Weisenmiller to Governor Brown saying he would deliver an action plan to prevent electricity blackouts while Aliso capacity was diminished (can be found at http://docketpublic.energy.ca.gov/PublicDocuments/16-IEPR-02/TN210801_20160322T100019_212016_Letter_from_CECISOCPUC_to_EGB.pdf (Accessed October 2017). That action plan was delivered along with a technical assessment on April 20, 2016 and has been referenced previously in this report. Also, previously referenced was a June 17, 2016 workshop about impacts to oil refineries.

and suppliers to expand their availability.) 24-hour markets would make it easier for gas customers to balance their supply receipts with actual demand, particularly in providing a remedy for the issue of having to buy and nominate gas on Friday to meet demand through the weekend and into Monday. Storage (inside California or out) may still be needed in order for customers to balance flat production against lower weekend demand, but storage would not be needed by the utility and the Monday problem could be eliminated.

Summary of Market Mechanisms

Table 19 summarizes operational and market mechanisms which could reduce dependence on underground gas storage. Regulatory and operational changes can help, but do not eliminate the need for underground gas storage to meet winter demand and do not seem able to have much further impact on our use for daily balancing.

Some of these operational and market alternatives are already being implemented given the reduced use of Aliso Canyon; they are therefore already achieving what they can in the SoCalGas system. If all storage were eliminated, implementation of the market and operational alternatives would need to expand to cover the PG&E system. In particular, the balancing rules would likely need to become even tighter. The change to core balancing rules should help to reduce the need for storage, depending on the error range between daily forecasts of core demand and actual core demand, and how much of that error we can eliminate – an unknown at present. The market changes that require approval outside of California do not lend themselves to more accurate quantification of benefit. Moreover, they require outside approvals that do not appear obtainable by 2020, even though we note several changes were adopted quickly as part of the reliability action plan to avoid electricity blackouts with Aliso Canyon's reduced capabilities.

Table 19. Operational and Market Alternatives to Underground Gas Storage.

Tighter Balancing Rules	• Sempra has moved to 8% balancing. • Can reduce to 5% balancing on a daily basis when needed. • These changes have reduced need to use gas storage by 0.15 Bcfd.
Balancing Core to Actual Load Instead of Forecast	• Sempra filed proposal in September 2017 as required (CPUC review pending). • Could reduce use of storage for difference between actual load and forecast.
Greater Use of Linepack (the ability to store gas by compressing it into the pipelines)	• Raises safety concerns as Sempra has very little linepack. • They can only store about ~0.13 Bcfd by compressing gas in their pipelines. • They strive to get their system back into balance before the start of each gas day. • PG&E has ~0.4 Bcfd of linepack and already uses what it has. • If new intrastate pipeline capacity were added, linepack capability might increase by 50%.
Closer Gas-Electric Coordination	• Unprecedented levels of coordination implemented after the Aliso event means further gains will be more difficult. • There could be benefits from formalizing joint reliability planning.
Advance Notice on Expected Burn and Day-Ahead Limits on Gas Burn	• Both electricity balancing authorities are doing this now for southern California. • Advance notice aids generators in complying with tighter gas balancing. • When gas burn is limited, it creates uneconomic dispatch. • No studies available on feasibility for northern California or that calculate minimum EG gas burn needed to prevent blackouts.
Shifting Generation to Out-of-Area	• When available, shifting to other generators outside a constrained gas area can avoid the need to pull gas from storage. • However, higher electricity prices will result from uneconomic dispatch. • No studies are available on feasibility for northern California or that calculate minimum electricity generation gas supply needed to prevent blackouts.
Shaped Nominations and Hourly Gas Market	• Hourly natural gas prices would require industry-wide acceptance. • Could potentially send price signals to reduce gas consumption during peak hours or hours when storage would have provided balancing service. • Shaped nominations would require the support of some storage or available linepack.
Weekend Natural Gas Market and Nominations	• Requires industry-wide acceptance. • Prior discussions of this concept were not fruitful. • Could help all customers and shippers (but especially electricity generation) by eliminating the Friday nomination for Sat/Sun/Monday. • Would allow more realistic opportunity with balancing loads on weekends.

Finding: Regulatory and operational changes can help to reduce reliance on underground gas storage, but will not eliminate the need for these services.

Conclusion 2.17: Operational and market alternatives do not eliminate the need for underground gas storage to meet winter demand, which serves to overcome the physical difference between peak winter gas demand and the capacity of pipelines to deliver gas. Nor will these measures have much impact on reducing the need to use storage for daily balancing.

1.5 How will new integrity and safety rules affect natural gas reliability?

New safety regulations for storage operations and maintenance by both state and federal authorities were adopted following the Aliso Canyon well leak starting with the Division of Oil, Gas and Geothermal Resources (DOGGR)'s Emergency Regulations in January 2016 (California Department of Conservation, 2016). In July 2016, DOGGR released a discussion draft of proposed permanent regulations that would apply to all storage operators. Those regulations remain to be finalized in 2017.[119] The federal government enacted regulations to address the need for safe and reliable operations of natural gas storage fields after the Aliso Canyon gas well loss-of-containment (Government Publishing Office, 2016). These regulations were the first to cover "downhole facilities" including wells, wellbore tubing and casing or the operations, maintenance, integrity management, public awareness, and emergency response activities associated with these downhole facilities.

These new regulations affect the natural gas storage capability in California because the reduced effective well diameter reduces injection and withdrawal rates, limiting the ability of the UGS facility to store or withdraw gas over short time periods. Additionally, wells will have to be taken out of service more often for testing (with longer outages should the tests indicate additional maintenance is required). The new regulations could also increase the cost of the UGS facilities when tubing, packer, and new wider-diameter tubing must be purchased. If increased costs are not recovered in a rate case, operators could also retire or abandon wells because they could not afford to meet the new regulations. This would reduce the amount of gas stored, injected, or withdrawn at the UGS facility.[120] Highlights of the new requirements include:

119. See Discussion Draft, California Code of Regulations, Title 14, Chapter 4. Development, Regulation and Conservation of Oil and Gas Resources, Article 4 (California Department of Conservation, n.d.). Requirements for Underground Gas Storage Projects. At http://www.conservation.ca.gov/dog/Documents/GasStorage/Public%20Discussion%20Draft%20-Requirements%20for%20Underground%20Gas%20Storage%20Proj.pdf (Accessed May 2017). The comment period on these proposed rules ended July 13, 2017. See: http://www.conservation.ca.gov/dog/Documents/GasStorage/Public%20Discussion%20Draft%20-Requirements%20for%20Underground%20Gas%20Storage%20Proj.pdf. Accessed July 2017.

120. Depending on interconnectivity within storage facilities that have more than one reservoir, such as Aliso Canyon, total storage capacity may also be reduced according to which wells are taken out of service.

- Improved inspection and leak protocol for all wells, pipelines, wellheads and a 100' radius from the wellhead. (PHMSA)

- Demonstration of the integrity of the underground storage reservoir or cavern using appropriate monitoring techniques for integrity changes, such as the monitoring of pressure and periodic pressure surveys, inventory (injection and withdrawal of all products), product levels, cavern subsidence, and the findings from adjacent production, water and observation wells. (DOGGR)

- Injection and withdrawal will no longer be allowed to occur through production casings; operators will instead be limited to use of only the tubing inside the production well casing. (DOGGR)

- Mechanical Integrity Testing (MIT) pursuant to SB 887 (which also requires each operator to have an MIT plan in place by January 2018).

Under Order 1109, applying only to SoCalGas, DOGGR required SoCalGas to complete six tests - aimed at demonstrating the safety of Aliso Canyon before it could return to injection.[121] In performing these tests, SoCalGas removed the old tubing and replaced it with larger-diameter tubing. As of fall 2017, SoCalGas had completed testing (and any associated remediation work) on 52 of the total 113 wells at Aliso Canyon and made them available for withdrawal.[122] The regulations give SoCalGas one year to test and remediate remaining wells or to put them permanently out of service. SoCalGas must also determine the rate to conduct the tests, replace tubing, and perform other remediation that may be found necessary as the tests are conducted.

Preliminary indications from SoCalGas to the joint agencies preparing the reliability action plans are that no more than 50 to 60 wells out of the 113 will ever be available again, absent drilling of new wells. Withdrawal capability using the wells tested to date at current inventory of ~14 Bcf is currently 320 MMcfd (CEC, 2017b). This could rise to 500 MMcfd if some reinjection occurred – more gas in the field would raise pressures and allow the 14 Bcf in the field to be withdrawn at a faster daily rate. It would also increase if additional wells passed through the testing and tubing replacement process so that there were more wells available. In reality, the field might never again be capable of supporting the 86 Bcf of inventory, 413 MMcfd of injection, and 1,860 MMcfd withdrawal it once provided.

121. SB 380 (Pavley) Chapter 14, Statues of 2016 subsequently codified the process for returning Aliso Canyon wells to service.

122. SoCalGas applied to the CPUC and DOGGR in November 2016 for approval to return these same wells to injection service; that request was granted in July 2017. The County of Los Angeles subsequently obtained a temporary injunction on any injection; California's 2nd District Court of Appeals lifted that injunction on July 29, 2017. See http://mynewsla.com/life/2017/07/30/aliso-canyon-safe-ok-to-reopen-dramatic-reversal-by-appeals-court/. Accessed July 2017.

SoCalGas announced on February 15, 2017 that it would immediately implement a Storage Safety Enhancement Plan (SSEP) in all of its gas storage facilities to comply with the DOGGR regulations that, on that date, were still in draft form. This work would conduct the same six tests as those required at Aliso and reconfigure the wells at the La Goleta, Honor Rancho, and Playa del Rey storage fields to tubing flow only. Some work started March 1, 2017 and SoCalGas planned that all wells not converted by April 1 would be temporarily plugged until they were tested and the tubing replaced. This plan would have reduced the withdrawal and injection capacity of each of the storage fields – reducing it to virtually zero for this summer (CPUC, 2017a). It would also permanently reduce injection and withdrawal capability going forward unless additional wells are added. Owing to reliability concerns, the CPUC, on March 16, 2017, directed SoCalGas to modify the Storage Safety Enhancement Plan (SSEP) in order to maintain withdrawal capability of 2.065 Bcf per day at the other fields and 2.420 as other wells are tested and become available for withdrawal at Aliso Canyon.

PG&E began talking about impacts from the proposed permanent DOGGR rules earlier this year. It briefed State agencies in early 2017 and met with customers and rate case participants in May. PG&E finds that moving to tubing-only would reduce injection and withdrawal capability by 40%, absent drilling new wells.[123] They project an increase in operation and maintenance (O&M) of over 200% per year to perform the annual integrity assessments and an increase in capital expenditure by 40%, including the drilling of 50 new wells to maintain current withdrawal capacity. Without those new wells, PG&E would be unable to withdraw the 1,270 MMcfd of withdrawal capability reserved to serve core customers in winter months. These projected costs appear to have led PG&E to announce in a customer meeting on May 11 that it would seek to retire its two smaller gas storage fields and replace them with gas from the independent gas storage fields.[124] More information will become public once PG&E files its next Gas Transmission and Storage rate case in the fall.

Taking the current utility-owned withdrawal capacity of 4.8 Bcf, less 40%, leaves 2.9 Bcf per day withdrawal capability (when the fields are at maximum inventory). This 2.9 Bcf plus California's intrastate pipeline take-away capacity of 7.5 Bcf yields a maximum servable demand of 10.4 Bcf per day assuming no gas pipeline or compressor facility outages of any kind. This would be adequate to serve 2020's aggregate statewide 1-in-10 winter peak day

123. PG&E Storage Update Meeting with CEC, January 18, 2017. Logically, going to tubing-only instead of injecting through tubing and the casing reduces the volumetric flow capacity. The CPUC, in its July 19, 2017 report "Aliso Canyon Working Gas Inventory, Production Capacity, Injection Capacity and Well Availability for Reliability" noted one of its key uncertainties in calculating how many wells are needed for reliability is that "the performance of wells using tubing-only flow as required by Senate Bill 380, as opposed to flowing gas through tubing and casing."

124. We submitted to PG&E a request for a copy of the 'reliability and cost' analysis mentioned by Senior VP Mel Christopher at the meeting. It was not available to us prior to the time of publication.

demand of 10.249 Bcf shown in Table 6. It would not, however, be enough to serve the 2020 forecast of a 1-in-90 winter peak day demand of 11.845 Bcf. Thus, after taking into account the reduction in storage from the new rules, California's utilities would not be able to meet any demand above 10.4 Bcf per day. As described previously, in its 2018 Gas Transmission and Storage (GT&S) rate case, PG&E proposed replacing the reduction of storage by contracting with independent storage. SoCalGas does not have this option because there is no independent gas storage connected to its system.

In theory, operators could replace the lost capacity by drilling additional wells sufficient to meet the 2020 winter peak with implementation of the DOGGR rules. Pursuant to Public Utilities Code Section 1005, utility capital investments over $50 million require submission of and CPUC approval of a CPCN. Given that no such applications have been filed yet and assuming 12 months at least to process and approve, it might be barely possible to do the planning, obtain the regulatory approvals, and drill any new wells by 2020.

Conclusion 2.18: In the 2020 timeframe, California's utilities will need to replace some, if not all, of the storage capacity that will be lost by complying with new California regulations to continue to meet peak winter demand. California's independent storage providers will also need to replace some, if not all, of their lost injection and withdrawal capacity, if they want to maintain historic operating levels.

Pipeline safety measures will also have an impact. The CPUC (in Rulemaking 11-02-019) and PHMSA adopted more rigorous requirements for pipeline integrity management after the September 2010 explosion of a PG&E high pressure gas transmission pipeline at San Bruno that killed nine people and destroyed 38 homes. Those integrity management obligations require the utilities to conduct in-line inspection or take pipelines out of service for hydrostatic testing. When anomalies are found, depending on their severity, the operator may have to take pipeline segments out of service until remediation can be performed. In some cases, the utility must secure various local and environmental permits before the work can be performed.

For example, SoCalGas currently has Line 3000 out of service while remediation work occurs. Additionally, its southern mainline is operating at 80% of maximum allowable operating pressure (MAOP), which reduces capacity by about 200 MMcfd, until hydrostatic testing of the line can occur.

The CPUC directed both utilities (in Rulemaking 11-02-019) to develop pipeline safety plans. PG&E proposed spending $2.2 billion over 4 years on work consisting of strength testing, in-line inspection (ILI), upgrades on various segments to allow ILI, the replacement of 186 miles of pipeline, and the automation of 228 valves. PG&E's plan and implementation timeframe is summarized in Figure 26.

Work Streams	2011	2012	2013	2014	Phase 1
Strength Testing*	236 miles**	185 miles	204 miles	158 miles	783
Pipeline Replacements	0.3 miles	39 miles	64 miles	82 miles	186
ILI Upgrades	--	78 miles	121 miles	--	199
In-line Inspections	--	--	78 miles	156 miles	234
Valve Automation	29 valves	46 valves	90 valves	63 valves	228
Records Integration	Data Validation, MAOP Calculations, Integrated Asset & Work Management				
Interim Safety Measures	Pressure Reductions, Leak Surveys, Aerial Patrols				

Figure 26. PG&E Pipeline Safety Enhancement Plan.
Source: PG&E

SoCalGas (including affiliate SDG&E) proposed spending $1.43 billion to modify 541 valves, install backflow valves (or check valves) to prevent gas from flowing into sections intended to be isolated from other connected lines, expand private radio networks, install remote leak detection equipment, and increase patrols and leak survey activities. The two would also pressure test or replace 385 miles of pipeline (CPUC, 2014a). Current work has Line 3000 out of service while remediation work occurs. (Envoy™ currently shows Line 3000 expected to be back in service sometime in the fourth quarter of 2017). Additionally, SoCalGas' southern mainline is operating at 80% of MAOP, which reduces capacity by about 200 MMcfd, until hydrostatic testing of the line can occur.[125] SoCalGas also has an outstanding request in A. 15-09-013 for a CPNC to build a new 47-mile line paralleling its existing Line 1600 from the Rainbow Metering Station in Riverside County to San Diego. This project is said to be needed so that Line 1600 can be taken out of service and pressure-tested pursuant to CPUC rules. SoCalGas and SDG&E estimated construction costs of $596 million (SDG&E and SoCalGas, 2015).

The storage integrity work needs to be coordinated with remaining pipeline integrity work in order to preserve reliability. It appears PG&E is already thinking about impacts to reliability from the new storage rules (based on its briefings and rate proceeding discussions). It is less clear at this point that SoCalGas is synchronizing its SSEP with reliability planning, or what it might be thinking in terms of drilling replacement wells in

125. See Maintenance Schedules at https://scgenvoy.sempra.com/. Accessed July 2017.

the near-term. Implementation of the new DOGGR rules and coordination with pipeline safety enhancement plans provide a good opportunity to revisit and clarify the importance of reliable gas service to electric generators. This importance could be better reflected in California's natural gas services and tariffs.

What are the rate impacts of closing storage facilities?

There is little experience retiring gas storage facilities in the United States. California, however, has retired some.[126] All of these appear to have been retired for operational reasons. Some retirements could have been related to safety, but we do not have enough information to draw more precise conclusions about how safety related to these retirement decisions. Examples of storage facility retirements are given in Appendix 2-9.

Whether additional fields would need to be retired due to test findings is unclear at this time. Whether doing so entails a net cost or yields a net benefit seems to depend on the prices prevailing when the gas remaining in the field is sold and likely the value of the land involved. We cannot determine whether additional issues might arise if fields are retired.

At this time, there are more policy questions than answers about the process and implications of closing storage facilities. The utilities' financial concerns require that a significant portion of O&M costs be recovered in rates. What cost-benefit analysis will the CPUC use to assess the value added of storage vs. these new costs? At what level of cost will the CPUC or the utilities balk at the increased storage costs that have to be passed on to consumers? Would the CPUC approve of the utilities unilaterally abandoning the storage sites? How will the new rules apply to independent storage vis a vis the recovery of costs? Could independent companies declare bankruptcy and walk away?

126. Abandonment would be the formal regulatory term describing the state of a field, pipeline, or well that has been removed from service permanently, after environmental remediation and removal from rate base.

1.5.1 Financial Viability and Investment in Maintaining Storage Assets

The new safety and integrity rules may affect the financial viability of specific underground gas storage fields depending on the new spending required. There is some public information about O&M costs and capital expenditures for the utility-owned storage facilities. Appendix 2-10 explores that information to help readers understand the pattern of investment in these facilities that might affect their condition. It does not present a full valuation analysis. This information can also help form the basis to begin thinking about the financial value of these facilities that might need to be taken into account if California decided to retire any of these facilities.

Finding: PG&E and SoCalGas spent an average of $500,000 per Bcf of cycling capability in 2015 on O&M at their storage facilities. Over time, those expenses appear to have increased at a rate similar to inflation. We could not determine, from information in the public domain, the condition of gas storage facilities or if O&M expense and capital expenditure has been sufficient to maintain the facilities or whether the independent facilities are in better condition and if this might be the case because they are regulated differently or because their owners focus on storage and storage alone.

Recommendation 2.2: DOGGR should conduct detailed facility condition assessments by independent analysts or with stakeholder review, and determine if the level of investment to date is adequate, taking into account the expected cost to implement the new DOGGR rules. This could include an assessment to determine what, if any, impacts occur as a result of different business and regulatory models for utility versus independent storage.

Simply adding the reported transaction and book values yields a very high-level total potential value of $2 billion as an estimate of compensation (note that this does not address depreciation or other issues) that might be due to owners should California conclude that underground gas storage is not viable and decide to eliminate facilities. At the same time, the newer condition of the independent facilities, their owner's ability to focus on operating and maintaining them, and the competition that goes on inside a utility for budget dollars and in a rate case should at least make one pause and ask if we want our utilities to be in the gas storage business. Are there benefits or any reduction in risk to other business models? Answering that question goes beyond the question of viability but could be something the State wants to consider if it more expansively addresses the future of underground gas storage in California.

Again, this analysis cannot determine if O&M expense and capital expenditure has been sufficient. Any inability to invest adequate ratepayer dollars into utility gas storage facilities is a threat to viability and the CPUC will need to take into account likely higher spending requirements for underground storage going forward. This may be more difficult for the independent storage facilities since current market conditions limit what they can charge subscribers.

APPENDIX 2-1: Nominations, Scheduling, and Balancing

Non-core customers must nominate and schedule their delivery of gas supply with the utility. Nomination and scheduling is a request for a physical quantity of gas under a specific purchase, sales or transportation agreement to be delivered. It must be receipt and delivery point-specific. Essentially it is a nomination from a shipper to advise the pipeline owner or utility of the amount of gas it wishes to transport or hold in storage on a given day or days. A nomination will continue for a specified number of days or until superseded by another service request for the same contract.

Since many end-users use a third-party agent to handle their nominations, scheduling, and balancing, the end-user must also submit a matching nomination. In essence, this matching nomination is confirmation that the transaction is valid.

A utility uses the scheduled quantities to determine if there is enough capacity on their system to meet demand on a given day or if it has enough gas being delivered to meet all demand. When firm shippers schedule deliveries to a specific receipt point that exceed that point's capacity at the scheduled time, the utility (or pipeline) "cuts" or reduces the requested quantities pro rata. This occurs with each utility or pipeline from the customer all the way back upstream to where gas is produced at the wellhead.

Rules specified in both the PG&E and SoCalGas tariffs require customers to bring in each day what they will use that day, and deliveries are supposed to be evenly split, or, equal in each hour. A difference between a customer's usage and the volume of gas scheduled for delivery is called an "imbalance." With small imbalances, this free storage is provided within the pipeline's line pack.[127] In the case of an over delivery, the imbalance represents free storage. The utility must effectively store the extra gas in the pipeline. Conversely, a customer might bring in less gas than scheduled essentially use line pack to cover its nominated usage. Bigger imbalances cannot be addressed with line pack, and today are met with gas from underground gas storage. Both PG&E and SoCalGas use a portion of their storage assets to provide additional balancing services above and beyond what can be accommodated with line pack (PG&E Storage Assets Available for Balancing and Market Center, n.d.).

Under the 1990 CPUC transportation imbalance rules, both PG&E and SoCalGas permit a tolerance band around scheduled gas quantities so that small errors between usage and scheduled quantities are allowed and incur no penalty. In other words, customers can have up to a 10% difference between their actual monthly usage compared to the gas they bring into the system. Customers have an entire 30 days after the delivery month to clear

127. Line pack is gas that is maintained in a transmission pipeline or distribution main to keep it pressurized enough that customers can take gas out of it without pressures dropping so low that gas stops flowing. Line pack is discussed further in Chapter 2 Section 1.4, in discussing potential alternatives to underground gas storage.

their imbalances by delivering make-up gas supply to the utility, delivering less gas if the imbalance was positive, or by trading out the imbalance with another party on the system. Imbalances that are not remedied may be cashed out at penalty prices.

The utility staff group that buys and schedules gas deliveries on behalf of core customers are also subject to the 10% monthly tolerance but the imbalance is calculated relative to forecasted demand instead of the actual demand. This essentially means that they are not held accountable for forecast errors whereas non-core customers (including generators) are held accountable for forecast errors. Arguably, they are getting free balancing for the portion of their imbalance caused by forecast error. The utility system operators manage this core customer imbalance (after line pack and offsets by other customers are used) with storage.

It is also relevant that most natural gas purchase contracts, often using a form of agreement adopted as the industry standard by the North American Energy Standards Board (NAESB), specify a flat daily delivery of natural gas. If the user's requirements vary, the contract might include an option to "swing" up to a specified quantity. In other words, one might contract to purchase 11,000 MMBtu per day, with the ability to swing that purchase quantity up to 14,000 MMBtu. The 11,000 MMBtu base quantity is to be taken every day, and would likely be priced at the index price posted on the InterContinental Exchange (ICE), at say, "SoCal Border." If the user needs less than 11,000 MMBtu on a given day, it would either have to sell the excess gas into the daily spot market, leave it as an imbalance which must then be corrected next month by either trading it out, or paying the sale or buy-back penalty stated in the utility tariff. Alternatively, the customer can nominate to inject it into storage, assuming they have purchased rights to use storage.

Table 20. Nomination and Scheduling Cycles (PST).

Cycle	Nomination Time	Confirmation Time	Becomes Effective
Timely	11:00 am Day Prior	3:00 pm Day Prior	7:00 am Day Of
Evening	4:00 pm Day Prior	7:00 pm Day Prior	7:00 am Day Of
Intraday 1	8:00 am Day Of	11:00 am Day Of	12:00 pm Day Of
Intraday 2	12:30 pm Day Of	9:00 pm Day Of	4:00 pm Day Of
Intraday 3	5:00 pm Day Of	8:00 pm Day Of	8:00 pm Day Of

Source: Compiled by Aspen Environmental Group

Looking at the five scheduling cycles portrayed in Table 20, several points are worth noting. First, even the intraday cycles have a gap of three to four hours from when the nomination is submitted to when the nomination becomes effective and the gas flows. Second, the cycles do not allow one to swing up on a nomination to take more gas in just a few hours. The new nomination still represents a daily take, spread over 24 hours. If only 8 hours remain in the gas day, then the daily nomination's impact will be 8/24ths of the daily quantity nominated. Notably, the "timely" gas cycle nominations are due before the CAISO announces its natural gas dispatch at 1pm Pacific Time. This means that electric generators to a certain degree are "guessing" when they submit their gas nominations as to how much natural gas they will burn tomorrow.

The pipelines and gas utilities operate in a construct of a "gas day" that starts at 9am Central Standard Time (CST), nationwide, (meaning 7am Pacific Standard Time (PST) in California). That gas day is the same all across the country (whereas electricity varies by regional market). Gas is traded on the day prior to delivery, until about mid-day, after which fewer marketers are active and fewer have gas still available to respond to developments later in the day.

Appendix 2-2: Storage Fields in California and Key Characteristics

Facility Owner	Facility Name	County, City	Working Capacity[14]	Type of Field	Approximate Facility Age	Other Info
SoCalGas	Aliso Canyon	Los Angeles, Porter Ranch (near Northridge).	86 Bcf, with 1,860 MMcfd withdrawal	Depleted oil (115 wells).	Purchased by SoCalGas in 1972, former oil field. Oil well records dating as far back as 1940's. (Half of SoCalGas' total of 229 storage wells are more than 60 years old, per Baker GRC testimony).[15]	The facility occupies 3,600 acres of surface area.[16]
SoCalGas	Playa del Rey	Los Angeles, Playa del Rey and part of Venice.	2.4 Bcf (have also seen 1.8 Bcf) with 400MMcfd withdrawal	Depleted oil (54 wells).	Oil well from the 1930's started operating in 1942. Purchased by SoCalGas in 1955.	There is a 2007 CPUC settlement due to suspected air/water contamination (see Fact Sheet).[17]
SoCalGas	Goleta	Santa Barbara, Goleta.	21 Bcf & 400MMcfd withdrawal	Depleted oil and NG (20 wells).	6 oil wells from 1929, then extracted NG, prior to storage use in 1941.[18]	Is SoCalGas' oldest facility in operation.
SoCalGas	Honor Rancho	Los Angeles, Santa Clarita/ Valencia.	26 Bcf & 1000MMcfd withdrawal	Depleted oil (41 wells).	Purchased from Texaco in 1975. There are 23 former oil fields (Texaco) dating back to the 40's, 18 drilled since by SCG.	Facility is located 10 miles north of Aliso Canyon at Valencia
PG&E	Los Medanos	Contra Costa, Concord	16 Bcf	Depleted NG	PG&E converted to storage in 1976.[19]	Parcel measures 318 acres.
PG&E	Pleasant Creek	Yolo, Winters	2.3 Bcf	Depleted NG	PG&E constructed in 1959.	Parcel measure 320 acres.[20]
PG&E	McDonald Island	San Joaquin	82 Bcf	Depleted NG	Originally produced NG for Standard Oil 1936.[21] PG&E purchased in 1958. Converted to storage early 1970's.	McDonald Island is below sea level and has contingency plans in place to continue operations when the Island floods.[22]
PG&E owns (25%) Private (75% Gill Ranch Storage LLC)	Gill Ranch	Madera, Mendota (~20 miles west of Fresno).	20 Bcf withdrawal = 650MMcfd	Depleted NG	Active NG extraction from 1943 - 1996; some limited production may still occur in a shallower formation. A. 08-07-032 & A. 08-07-033	Interconnection to PG&E Line 401, 27 miles to the west. (Gill Ranch Fact Sheet)[23]
Private (Brookfield LLC – acquired 2014)[24]	Lodi	San Joaquin, Acampo	17 Bcf withdrawal = 500MMcfd	Depleted NG	CPUC A. 98-11-012 for 10 wells.[25]	1450 acres surface space.
Private (Brookfield LLC)	Kirby Hills (operated as part of Lodi Gas Storage)	Solano, Fairfield	12 Bcf (inj & withd = 300MMcfd)	Depleted NG (15 wells + compressor and dehydrator	A. 05-07-017 and A. 07-05-009.[26]	Originally developed by Dow Chemical and purchased by Lodi ~ 2005. 6 miles to PG&E Line 400.

Facility Owner	Facility Name	County, City	Working Capacity[14]	Type of Field	Approximate Facility Age	Other Info
Private (Brookfield – acquired 2015)[27]	Wild Goose	Butte, Gridley	50 Bcf (650MMcfd injection and 1200MMcfd withdrawal)	Depleted NG (+ processing, compressor and dehydration)	Produced NG 1950's-80's. Began operating as storage facility in 1999 and expanded twice: A. 96-08-058, A. 01-06-028 & A. 09-04-021.	First independent storage facility. Connects to PG&E Line 167. Connection to Lines 400/401 near Delevan added later. Company indicates that its natural shale formation is good for preventing seeping.[28]
Private (AGL)	Central Valley	Colusa, Princeton	11 Bcf Withdrawal = 300MMcfd	Depleted NG (9 wells, compressor, saltwater disposal well)	Produced NG 1954-1992. Converted to storage 2010; A. 09-08-008.[29]	2200 ft underground; rural location. Connected to PG&E Line 172 outside fence and 15 miles to and Lines 400/401.

14 Withdrawal capability reported is maximum withdrawal potential at full field inventory.

15 https://www.socalgas.com/regulatory/documents/a-14-11-004/SCG-06_P__Baker_Testimony.pdf (SoCalGas, 2014b)

16 https://www.socalgas.com/regulatory/documents/a-14-11-004/SCG-06_P__Baker_Testimony.pdf (SoCalGas, 2014b)

17 https://www.socalgas.com/documents/safety/pdr_storage.pdf

18 http://www.independent.com/news/2013/may/23/la-goleta-gas-storage-questions-answered/

19 http://www.pge.com/nots/rates/tariffs/tm2/pdf/GAS_3489-G.pdf

20 http://www.pge.com/nots/rates/tariffs/tm2/pdf/GAS_3543-G.pdf

21 http://archives.datapages.com/data/specpubs/fieldst1/data/a007/a007/0001/0100/0102.htm

22 http://www.sfgate.com/business/article/Making-things-a-little-less-shaky-PG-E-pipeline-2555059.php

23 http://gillranchstorage.com/about-gill-ranch/faqs and ftp://ftp.cpuc.ca.gov/Environment/info/mha/gillranch/gillranch.htm

24 http://www.nasdaq.com/article/buckeye-closes-lodi-gas-sale-to-brookfield-infrastructure-analyst-blog-cm429612

25 http://www.cpuc.ca.gov/Environment/info/lodi/map.htm

26 ftp://ftp.cpuc.ca.gov/Environment/info/aspen/kirbyhills/kirbyhills.htm

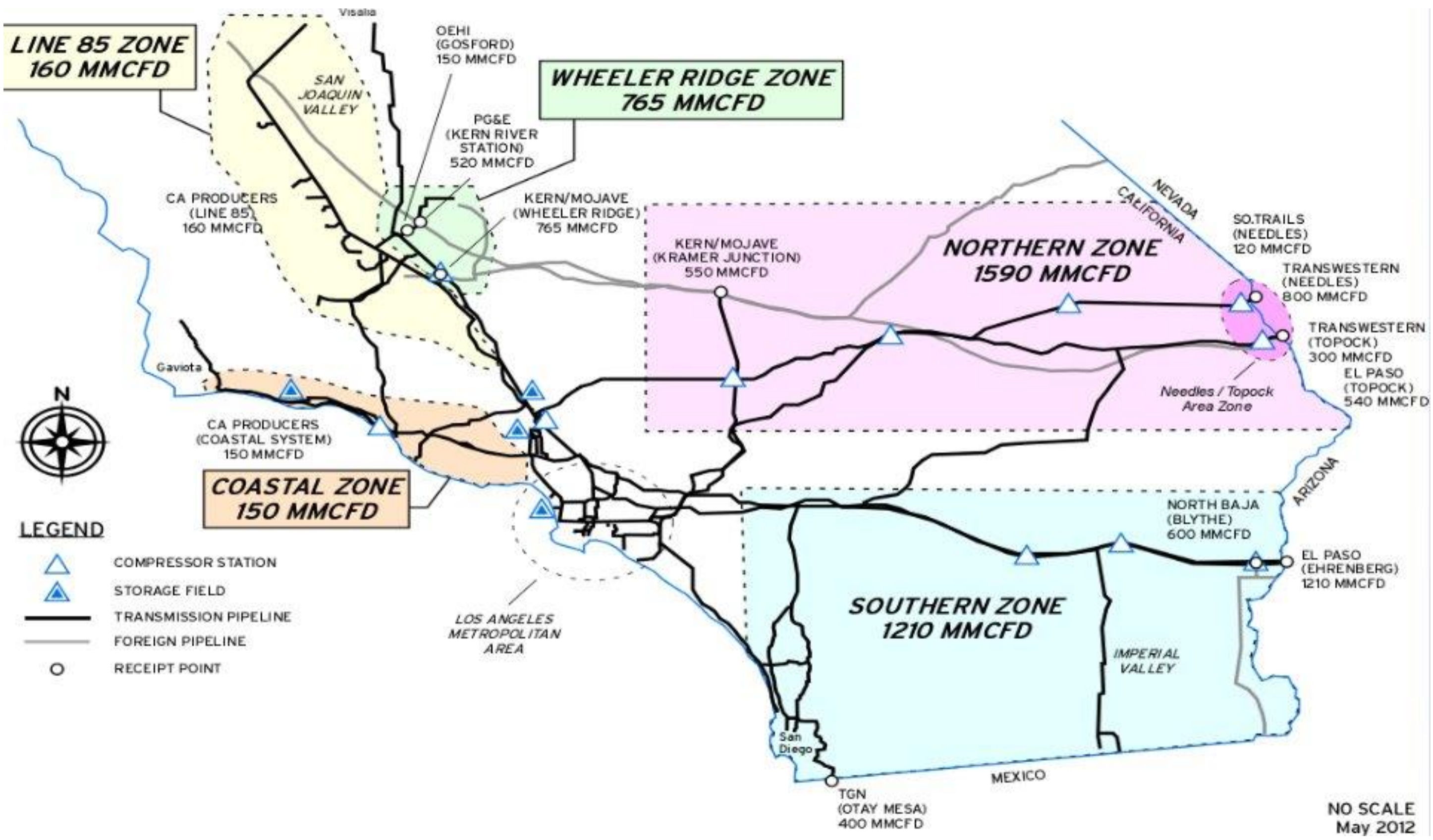
27 https://www.pehub.com/canada/2015/6/brookfield-led-group-to-acquire-niska-gas-storage-for-912-mln/

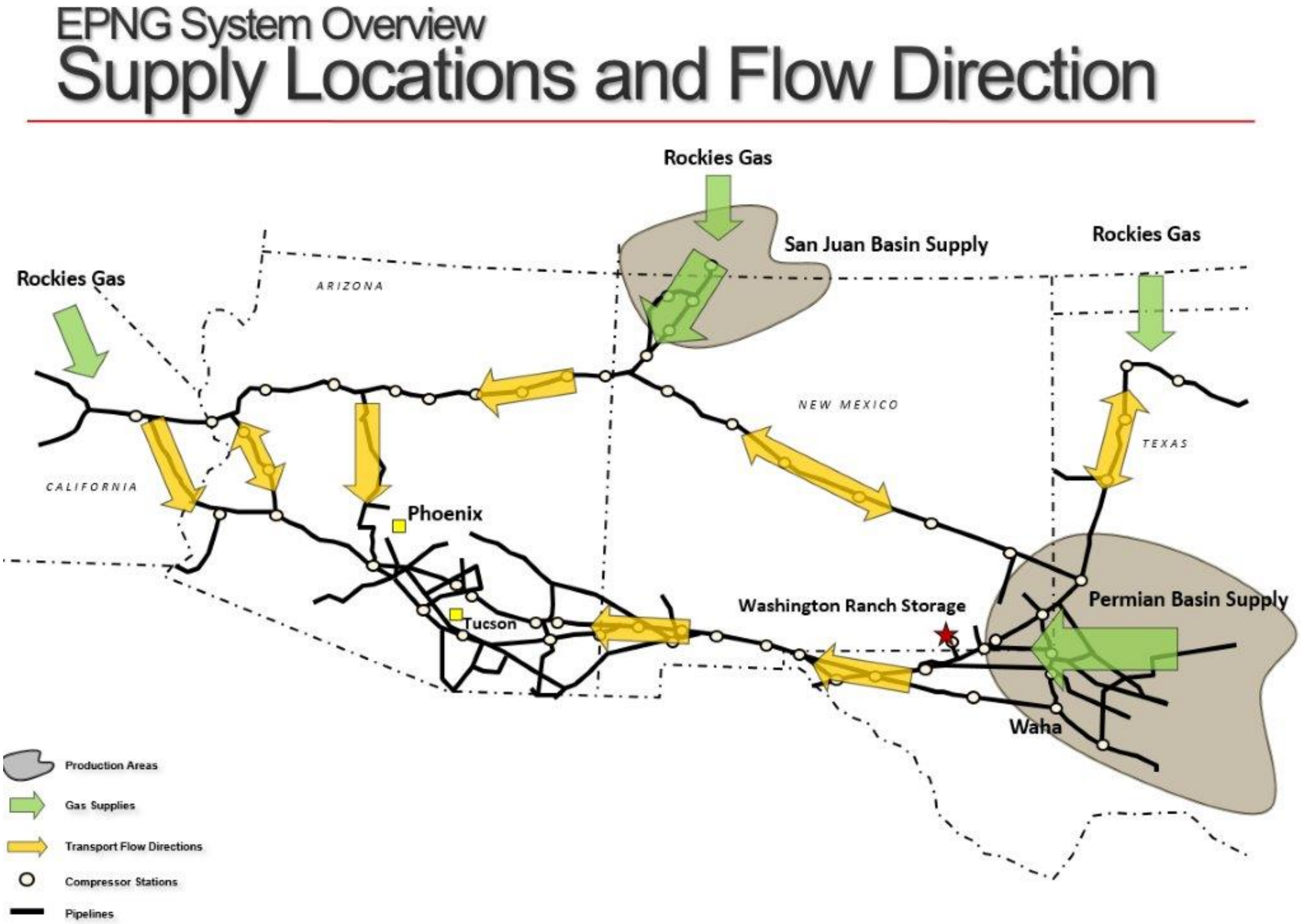
28 http://www.niskapartners.com/our-business/natural-gas-storage/wild-goose/project-details/ (Niska, n.d.)(Rock Point Gas Storage, n.d.)

29 http://cvgasstorage.com/localcommunity/overview.html

Source: CEC and Aspen Environmental Group

Appendix 2-3: Natural Gas System Reference Maps and schematics




EPNG System Overview
Supply Locations and Flow Direction
Rockies Gas
San Juan Basin Supply
Rockies Gas
Rockies Gas
ARIZONA
NEW MEXICO
TEXAS
CALIFORNIA
Phoenix
Tucson
Washington Ranch Storage
Permian Basin Supply
Waha
Production Areas
Gas Supplies
Transport Flow Directions
Compressor Stations
Pipelines


CaliforniaPipeline/StorageFacilities
PG&EGasServiceTerritory
PG&EBackbone
PG&ELocalTransmission
Interconnection
CompressorStation
PG&EGasStorage
IndependentStorageProviders
GillRanchStorageLLC/PG&E
SoCalGasStorage
SoCalGas
Kern/Mojave
KernRiverGasTransmission
KRGTHighDesertLateral
Mojave
NorthBaja
QuestarSouthernTrails
SanDiegoGas&Electric
Malin
Onyx Hill
Line 400/401
Tionesta
Burney
Gerber
Delevan
Wild Goose
Central Valley
Pleasant Creek
SACRAMENTO
Lodi
Los Medanos
McDonald Island
SAN FRANCISCO
Bethany
Gill Ranch
FRESNO
Kettleman
BAKERSFIELD
Kern River Station
Freemont Peak
Daggett
Hinkley
Essex
Line 300
Topock
Topock North
Topock South
LOS ANGELES
EHRENBERG
SAN DIEGO

Appendix 2-4: Montebello Storage Field Decommissioning Dispute

SoCalGas received permission to operate the Montebello Gas Storage Facility by the CPUC in 1955. The field allowed 3 Bcf of working inventory on 23 Bcf of cushion gas using the top two sands formations in the Eighth Zone of the West Montebello oil field (CPUC Nos. 00-09-034 and 01-06-081). SoCalGas obtained rights to operate the facility through leases with the various land and mineral rights owners that comprised the Eighth Zone. Over the years, SoCalGas purchased some surface rights to the facility, but much of their access to and use of the property was achieved via mineral and surface leases. In 1991, SoCalGas decided to purchase the remaining property, and initiated eminent domain proceedings in cases where they were unable to negotiate purchases with the land and mineral rights holders. In support of eminent domain, SoCalGas argued the facility was needed to maintain gas reliability on their system.

In 1997, soon after initiating condemnation proceedings in the courts to obtain the additional land and mineral rights, SoCalGas made the decision that the Montebello Gas Storage Facility was no longer needed for operations. Then-State Senator Calderon called attention to claims that SoCalGas had been untruthful in pursuing condemnation at same time it had decided the field was not needed. The Commission's Consumer Services Division (CSD) conducted an investigation and concluded that, prior to SoCalGas' representations to the LA Superior Court, the facility was required for operations and thus fell under eminent domain. SoCalGas had 1) decided that the facility was not needed, 2) not used the facility in over a year, and 3) initiated environmental review to be used in connection with disposing of the facility. CSD also found that SoCalGas may have acquired, through eminent domain, mineral rights at a greater depth than needed and at prices below the fair market value required to compensate sellers.

SoCalGas disputed these conclusions but settled by donating $3.5 million to the State's General Fund. The settlement also required SoCalGas to develop a course open to the public on professional responsibility and practice before the Commission, and to reduce rates in conjunction with refunding some of the mineral rights acquisition cost.

Appendix 2-5: AAEE Key Variables and Scenario Descriptions

Scenario Number	1	2	3	4	5
Scenario Name	Low case	Low-mid case	Mid case	High-mid case	High case
ET's	25% of model Results	50% of model Results	100% of model results	150% of Model Results	150% of Model Results
Building Stock	High Demand Case from 2011 IEPR	Mid Case from 2011 IEPR	Mid Case from 2011 IEPR	Mid Case from 2011 IEPR	Low Demand Case from 2011 IEPR
Retail Prices	High Demand Case from 2011 IEPR	Mid Case from 2011 IEPR	Mid Case from 2011 IEPR	Mid Case from 2011 IEPR	Low Demand Case from 2011 IEPR
Avoided Costs	High Demand Case from 2011 IEPR	Mid Case from 2011 IEPR	Mid Case from 2011 IEPR	Mid Case from 2011 IEPR	Low Demand Case from 2011 IEPR
UES	Estimate minus 25%	Estimate minus 25%	Best Estimate UES	Estimate plus 25%	Estimate plus 25%
Incremental Costs	Estimate plus 20%	Estimate plus 20%	Best Estimate Costs	Estimate minus 20%	Estimate minus 20%
Incentive Level	50% of incremental cost	50% of incremental cost	50% of incremental cost	50% of incremental cost	50% of incremental cost
TRC Threshold	1	1	0.85	0.75	0.75
ET TRC Threshold	0.85	0.85	0.5	0.4	0.4
Measure Densities	Estimate minus 20%	Estimate minus 20%	Best Estimate Costs	Estimate plus 20%	Estimate plus 20%
Word of Mouth Effect*	39%	39%	43%	47%	47%
Marketing Effect*	1%	1%	2%	3%	3%
Implied Discount Rate	20%	20%	18%	14%	14%
C&S Policy View	On-the-Books Initiatives	On-the-Books Initiatives	Expected Initiatives	Possible Initiatives	Possible Initiatives
Standards Compliance	No Compliance Enhancements, Compliance Rates Reduced by 20 percent	No Compliance Enhancements, Compliance Rates Reduced by 20 percent	No Compliance Enhancements	No Compliance Enhancements	Compliance Enhancements
Title 24 Updates	2005, 2008, 2013	2005, 2008, 2013	2016, 2019, 2022	2016, 2019, 2022	2016, 2019, 2022
Title 20 Updates	2005, 2006, 2008, 2009, 2011	2005, 2006, 2008, 2009, 2011	2016-2018 (Staggered introduction)	2016-2018 (Staggered introduction)	2016-2018 (Staggered introduction)
Federal Standards	Already adopted	Already adopted	Already adopted	Future Federal Standards	Future Federal Standards

Source: Navigant Consulting, p. 101. 2013 Potential and Goals Study. http://www.cpuc.ca.gov/General.aspx?id=6442452621

Appendix 2-6: Progress with Renewable Natural Gas

Many landfills have methane capture facilities, and a large number convert this biogas to electricity and sell that power to the grid or use it onsite.[128] SCAQMD recently made this harder by further reducing the acceptable level of NOx emissions from small engines and other regional air management districts are considering similar actions (SCAQMD, 2016a). Those that do not burn the gas on-site or feed it directly into vehicles may be able to inject this biogas into the pipeline; however, this requires a pipeline interconnection and significant investment to scrub the biogas of compounds for compliance with injection rules. Between landfills, wastewater treatment plants, and dairy manure digesters, a consultant

128. A CEC web page cites 56 landfill gas recover facilities existing in 1995, 42 of which collected gas to fuel 246 MW of electrical capacity. http://www.energy.ca.gov/biomass/landfill_gas.html (Accessed May 2017). AB 4037 (Hayden, Chapter 932, Statutes of 1988) prohibited the gas utilities from accepting landfill gas into their systems.

retained by SMUD estimated 1,980 MW of electrical capacity could rely on biogas in California, and twice that might be available West-wide.[129]

Pursuant to AB 1900 (Gatto, Chapter 602, Statues of 2012), the CPUC adopted standards on maximum concentrations for 17 compounds that may be found in biogas in California (Decision No. 14-01-034). Later, In Decision No. 15-06-029, the CPUC directed that the cost of complying with these standards to treat biogas and bring it to merchantable biomethane quality should be borne by producers, just as other gas producers who interconnect to the utilities' pipeline systems do. It recognized that the conditioning and interconnection costs are likely to make up a large part of the overall costs of biomethane projects, but that these costs are due to the inherent composition of the gas itself. Given current low natural gas prices, the CPUC provided $40 million in funding for incentives to help cover a portion of its interconnection costs. Projects that interconnect and successfully deliver gas for at least 30 days are entitled to an incentive of 50% of the interconnection cost up to $1.5 million. The incentive is available to cover interconnection costs only, not conditioning or any ongoing costs for labor, odorant, or equipment. Waste Management, a participant in the proceeding, estimated capital costs to construct conditioning facilities totaling $27.4 to $33.1 million and $2.5 to $3.1 for testing and recordkeeping. The Coalition for Renewable Natural Gas cited interconnection capital cost estimates of $1.5 to $3 million.

SoCalGas is following the lead of German utilities and is now experimenting with Power-to-Gas (P2G) projects as a champion of "decarbonizing the pipeline (Minter, 2014)." P2G uses electricity in excess of hourly needs to produce hydrogen. The conversion is accomplished via electrolysis, which passes an electric current through water to create H_2 and O_2. (Doing so uses energy, as does any conversion back to electricity, so total efficiency is reduced.) The oxygen can be sold into existing markets for breathable oxygen gas. The hydrogen can be stored and turned back into electricity later. It can also be combined with CO_2 to create methane, although the methanization process creates additional energy loss. That methane can then be fed into the natural gas system. The hydrogen can also fuel vehicles. The German gas utilities blend hydrogen in small quantities – up to 3% by volume – into their natural gas pipeline systems (Boren, 2016). SoCalGas cites 6% in France and as much as 12% in Holland. Some suggest that the hydrogen can be injected into a natural gas pipeline to supplement natural gas demand and that existing appliances can handle it safely (Melaina, 2013).

129. The consultant appears to have been Black & Veatch. See "Challenges and Opportunities of Biomethane for Pipeline Injection in California," slide 18, found at https://www.epa.gov/sites/production/files/2016-06/documents/21tiangco_.pdf (Accessed May 2017).

The CPUC and CEC have not gotten far in terms of analyzing the potential for renewable natural gas. The CEC, in its 2015 report pursuant to AB 1257 (Bocanegra, 2013) (which requires the CEC to produce a report looking at how to maximize the benefits of natural gas to California every three years), identified P2G, as it is often called, as a research area to explore (Bauer et al., 2015). P2G is also mentioned in the 2017 Integrated Energy Policy Report (IEPR) scoping order. The CPUC gave a cursory mention of the idea of using hydrogen production as demand response or as storage in its 2015 look moving beyond 33% renewables (CPUC, 2015c). The California Hydrogen Business Council describes P2G as "similar in scale to pumped hydroelectric and compressed air [storage] but is much more modular and flexible in siting and can utilize the vast storage capacity of the existing natural gas grid (California Hydrogen Business Council, 2015)." No analyses were found to describe exactly how this will occur.

SoCalGas, for its part in championing decarbonization, has mentioned looking at using "one of our storage facilities in terms of electric generation, carbon capture, power-to-gas hydrogen production, and methanation (VerdeXchange, 2015)." It is unclear exactly what that means, given the status of Aliso and the potential new DOGGR rules that may reduce underground gas storage capacity. SoCalGas has also encouraged the municipal utilities to look to P2G to help fulfill their SB 350 integrated resource plan requirements (Carmichael, 2017). SoCalGas currently has two P2G demonstration projects underway, one at UC Irvine and one in Colorado at National Renewable Energy Laboratory (NREL). As more renewables lower the marginal cost of production below that of natural gas, the economics of P2G will improve. Even so, the small quantity of renewable natural gas (RNG) expected to be available, and its likely flat production profile, may make both these concepts moot.

Appendix 2-7: Gas electricity coordination actions

CAISO sought stakeholder input and support for eight specific changes to its tariff. Without explaining the technical nuances of commitment bids, convergence bidding and so forth, the specific changes to CAISO's tariff approved by FERC include:

1. provide electricity scheduling coordinators with two-day ahead advisory schedules for information purposes to help with gas procurement decisions and gas scheduling;

2. use a more timely gas price index (i.e., prices obtained from the Intercontinental Exchange between 8 and 9am PST) for calculating commitment cost caps, default energy bids, and generated bids;

3. increase by 75% the gas price used to calculate commitment cost caps and 25% to calculate default energy bids, for generating resources served by SoCalGas or SDG&E so that CAISO's real-time market-clearing process can take into account the impact of gas system limitations and avoid further aggravating existing gas system constraints;

4. enforce a natural gas constraint in the real-time market clearing process that would limit the maximum amount of generation dispatched if dispatching more gas-fired generation would jeopardize gas and electric system reliability;

5. allow CAISO to deem certain [electricity] transmission paths non-competitive due to enforcement of the natural gas constraint;

6. make adjustments to [CAISO's] monthly congestion revenue rights auction and allocation process;

7. suspend convergence bidding [between the day-ahead and real-time markets] for purposes of market efficiency; and

8. permit scheduling coordinators to seek after-the-fact recovery of fuel costs related to commitment costs and energy bids from the Commission through an FPA section 205 filing. [130]

In addition, CAISO retains its "exceptional dispatch" tariff authority without change. Exceptional dispatch allows the CAISO to dispatch generators in an order not based on economics when needed. It also had, during summer 2016, the authority to reserve internal transfer capability and to adjust its congestion revenue rights auction and allocation process. In the winter update, CAISO advised FERC it believed it did not need these two changes going forward.

In approving these tariff changes, FERC referenced the finding crafted by the inter-agency group preparing the 2016 summer and winter Action Plans that reliability challenges will continue. CAISO and the agencies considered other mitigation measures, such as moving the timeline for submitting electricity bids so they would be due before gas is nominated. See Table 20 for nominations and scheduling timeline. CAISO told FERC it did not propose such a change because the additional time gap between submitting day-ahead bids and the real-time market would increase the day-ahead forecast error. This would eliminate any benefit of shifting the bid time and potentially increase the difference between receipts and demand.

The Action Plan team also considered whether SoCalGas could call operational flow orders (OFOs) earlier in the gas day. The gas utilities get scheduled delivery quantities confirmed back from the upstream pipelines at 3pm (again, see Table 20). That information allows the

130. See ER 17-110-000, "Order Accepting Tariff Revisions, Subject to Condition," November 28, 2016. Found at http://www.caiso.com/Documents/Nov28_2016_OrderAcceptingTariffAmendment_AlisoCanyonElectricGasCoordinationPhase2_ER17-110.pdf (Accessed May 2017). The tariff change request can be found at http://www.caiso.com/Documents/Oct14_2016_TariffAmendment_AlisoCanyonGasElectricCoordination_Phase2_ER17-110.pdf

utility to compare supply coming into its system with customer demand. If the gap between scheduled supply and expected demand is larger than the quantity the utility can address via line pack and storage, then the utility issues an OFO directing customers to more closely balance their supply and demand. Customers then go look for someone who can either use or give additional gas supply, depending on whether they need more or less gas supply delivered in order to comply. If OFOs could be called earlier in the day, electric generators would have more time to remedy their gas imbalances. This concept still appears on the mitigation measure list, held in reserve, as an idea that sounds good, but is still without an implementation approach. This is because information required for the utility to make the OFO determination is not available any earlier in the day and California cannot unilaterally require a change to the industry-wide nominations and scheduling protocols.

Calls for greater coordination between gas and electricity markets have been occurring since 2010, when American Public Power Association (APPA) published a consultant report describing, among other things, coordination issues generators would experience as they rely more on natural gas. Critically, the study pointed out the balancing problems caused by generators having to nominate and schedule gas before they know whether and to what extent their plant will be dispatched for the next electricity day. The study observed that many pipelines and states do not have gas storage, and that storage is the key to allowing the flexible balancing provisions that help make generators able to reliably provide electricity (Aspen Environmental Group, 2010).

A briefing to FERC Commissioner Moeller on the APPA gas study led him to ask parties for comments on coordination between the two markets. FERC subsequently opened a docket to discuss gas-electric coordination (FERC, 2012). FERC held five regional technical conferences to discuss 1) communications, coordination, and information sharing; 2) scheduling; 3) market structures and rules; and 4) reliability concerns. One of the concerns identified in those technical conferences was that the pipelines and electric utilities felt constrained in the information they should share without running afoul of FERC market power rules. FERC issued a rulemaking in 2013 to remove communication barriers between the two market segments (FERC, 2013).

In 2014, FERC issued an additional rulemaking to consider how to better coordinate the scheduling of natural gas and electricity markets and asked the North American Energy Standards Board (NAESB) to coordinate developing industry consensus. NAESB delivered a report containing agreement on only a narrow range of issues (FERC, 2014). CAISO, gas utilities, and merchant generators encouraged FERC not to take action. Many in the industry who asked FERC not to take action seemed to fear FERC would make things worse, not better. In the end, FERC issued Order No. 809, which adopted two small changes to the gas scheduling windows but backed away from the idea of creating an earlier start to the gas day, a single start to the gas and electricity days, or any number of other measures that would improve coordination.

Appendix 2-8: Experience with Flexible Nominations

In 2012, El Paso Natural Gas (EPNG) tested market interest in expanding its storage in eastern New Mexico's Eddy County. The market response appears to have resulted in a very small (4 Bcf) expansion of storage capacity that was scheduled to go into service in December 2015 (Kinder Morgan, 2015).[131] It also sought non-binding expressions of interest for a storage-backed, no-notice, or hourly nominated transportation service to be developed collaboratively with customers:

> *These services could provide shippers with firm receipt to delivery point service with either greater flexibility in adjusting same day nominations or without the Shipper having to nominate for such deliveries and receipts. The service could also provide shippers with additional flexibility in the event that actual requirements vary from nominated and scheduled volumes. In order to ensure that such service is operationally viable and addresses prospective shippers' needs, EPNG is proposing to engage in a collaborative process with interested customers for the purpose of developing mutually agreeable terms and conditions for a no-notice or hourly transportation service. Additional requirements for these services may include a firm transportation path which includes the receipt and delivery point for Washington Ranch. EPNG will evaluate each request to determine if operational firm capacity exists to serve the described service. Interested parties should contact their EPNG Business Development or Marketing representatives.*

We find no indication that this informal request for interest resulted in any change to EPNG's services. Since 2005, EPNG has offered a limited opportunity for shaped nominations, albeit at higher rates. Rate schedule "FT-H," which allows a three-hour peaking service in which a shipper may schedule up to 150% of its ratable hourly quantity (i.e., 1/24th of its maximum daily quantity) in three individual non-consecutive hours or 120% of the ratable hourly quantity for any twelve consecutive hours. It also allows a 12-hour and 16-hour peaking service, limited to 150% of the ratable hourly quantity for no more than 12 or 16 hours, respectively. Its 8-hour peaking service allows taking up to 300% of the ratable quantity for eight hours. These services are subject to minimum pressures being available in the pipeline, such as the 400 to 550 psig required for EPNG to provide the 8-hr and 12-hr services, compared to 250 psig for the ability to peak in only one of 3 hours in a day.[132] The pipeline itself determines what kind of flexible services it feels its system can offer.

131. http://passportebb.elpaso.com/ebbmasterpage/Notices/NoticesAutoTable.aspx?code=EPNG&status=Notice&name=Non-Critical%20Notices&sParam3=11966&sParam14=D&details=Y (Accessed April 2017). If there were no underground gas storage in California, EPNG might have gotten a larger response to its open season.

132. See El Paso Natural Gas Company tariff, Third revised Volume No 1A, Part III Rate Schedules, Rate Schedule FT-H, Version 8.0.0 found at: http://passportebb.elpaso.com/ebbmasterpage/Tariff/OrgChart.aspx?code=EPNG&status=Tariff&pdftag=cerllfsbsr(Accessed April 2017).

EPNG also offers a firm daily balancing service for up to 10% of a daily maximum delivery quantity. These daily balancing quantities must be nominated such that EPNG will carry an imbalance for a customer, up to a maximum quantity, if the customer scheduled the imbalance (whereas California allows the imbalance essentially to be without-notice and calculates it relative to monthly demand, not daily). Shippers have 30 days to remedy the imbalance. EPNG also offers an hourly no-notice service. Such service is at EPNG's discretion, when system conditions permit, and is limited by the hourly firm service terms and quantities described above, including the availability of sufficient pressure on the El Paso system at the customer's specified delivery point.

EPNG, however, does not offer these services to customers with California delivery points (those delivery points would be the transfer points into the PG&E and SoCalGas systems at Topock and Ehrenberg). Table 21 shows the rates shippers pay for firm transportation (FT-1) versus the flexible take services. The total cost (i.e., reservation charge plus usage charge) for the flexible take services ranges from nearly 17% higher for the 12-hours of relatively small flexibility versus flat FT-1 service, to 100% higher for the 8 hours of flexibility to swing up to the 300% of daily average quantity. Using the swing services also requires the shipper to select a swing quantity, reserve it in advance, and pay the reservation portion (i.e., the much larger portion) of the rate regardless of whether it is used – every day. Violations of these quantities when critical condition notices are in place range from 1.5 to 2.5 times the normal rate for firm transportation (FT) service. Balancing and storage service for other quantities or hours of flexibility costs an additional 29.44 cents per MMBtu.

EPNG is perceived to have expanded pipeline segments, particularly to serve the Arizona shippers, to help provide these enhanced services. EPNG has also tailored the offering (i.e., the percentage and hours of allowed deviation from flat deliveries) to limits that reflect the ebb and flow around its nearly 1 Bcf per day of line pack.

Table 21. EPNG Rates for Firm and Flexible Transportation Services.

State	Component	Rate Schedule ($/MMBtu)				
		FT-1	FTH-3	FTH-12	FTH-16	FTH-8
California	Reservation	$0.4514	N/A	N/A	N/A	N/A
	Usage	$0.0318	N/A	N/A	N/A	N/A
Arizona	Reservation	$0.4514	$0.4966	$0.5267	$0.5643	$0.9028
	Usage	$0.0318	$0.0350	$0.0371	$0.0398	$0.0637
New Mexico	Reservation	$0.3396	$0.3735	$0.3962	$0.4245	$0.6791
	Usage	$0.0235	$0.0258	$0.0274	$0.0294	$0.0470
Balancing & Storage		$0.2944				

Source: EPNG Tariff Summary of Rates

Looking at who subscribes to the flexible services confirms this view. Table 22 is compiled from the Index of Shippers posted on EPNG's Passport information system, as required by FERC. Each of the shippers identified is an integrated electric utility or a gas utility. Together, they account for about 740 MMcfd (776,000 MMBtu) on total throughput that from 2009 to 2014 ranged between 3,700 and 4,700 MMcf.[133] These integrated gas or electric utilities are allowed by their regulators to pass these costs on to ratepayers; they are not the independent generators and they are not entities bidding into competitive electricity markets. Under current market conditions, the inability of generators to recover fixed gas costs in electricity markets is an impediment to the use of services such as firm capacity or storage.

Table 22. EPNG Shippers Holding Flexible Services.

Shipper Name	**Rate Schedule**	**Maximum Daily Quantity (MMBtu)**
Arizona Electric Power Cooperative, Inc.	FT-H12	7,424
Arizona Electric Power Cooperative, Inc.	FT-H8	8,553
Arizona Public Service Company	FT-H8	39,902
El Paso Electric Company	FT-H16	175,000
Public Service Company of New Mexico	FT-H12	23,500
Salt River Project Agricultural	FT-H12	230,000
Southwest Gas Corporation	FT-H3	75,400
Texas Gas Service, a Division of ONE	FT-H3	118,927
Tucson Electric Power Company	FT-H12	40,000
UNS Gas, Inc.	FT-H3	54,755
UNS Gas, Inc.	FT-H12	2,310
Total		**775,771**

Source: Aspen Compilation from Index of Shippers

133. The throughput comes from "El Paso Natural Gas Pipeline 2014-15 Winter Preparedness," Presentation to the Arizona Corporation Commission by Kevin Johnson (Director of EPNG/Mojave Western Region Gas Control)

The difficulty in implementing these types of services in California is that they cannot be provided absent some amount of gas storage or absent excess pipeline capacity that can be packed with enough extra gas to meet the contracted peaks. EPNG said as much in an Operations Description and Expansion summary it submitted in its 2005 rate case at FERC (FERC, 2007):

> **Washington Ranch** – *Washington Ranch, El Paso's only storage field, is operated as an auxiliary line pack facility to help dampen swings created by imbalances. Although all of El Paso's firm transportation agreements call for ratable takes, many shippers in the EOC market area have difficulty complying with that requirement. At the sorts of relatively low loads experienced in the recent past, El Paso can accommodate more of this non-ratable flow behavior than would be possible if the system were running at full load. Washington Ranch, which is located on the east end of El Paso's Southern Low Pressure System, is used to help dampen the impact of both non-ratable takes and daily imbalances. Because of its location on the system (i.e. relatively distant from the major south system load centers), Washington Ranch is most useful for covering daily imbalances.*

Appendix 2-9: History of Gas Storage Facility Closures in California

SoCalGas' Montebello gas storage facility is an example of a field that has been retired. SoCalGas decided in 1997 that the Montebello Gas Storage Facility was no longer needed for operations[134] and submitted to the CPUC Application No. 00-04-031 requesting permission to recover its 23.7 Bcf of cushion gas and decommission the field. That field had been converted to gas storage in 1956.

The CPUC approved that application in 2001. In so approving, the CPUC cited its expectation that it was less worried about needing Montebello in winter than it was about summer demand constraining the ability to fill its other storage in summer (for use in winter):

> *"ORA, TURN, and SoCalGas agree that the potential for inadequate storage next winter is not due to insufficient storage capacity but rather to the extremely high demands on existing [gas] transmission to serve competing uses – daily consumption, including high demand by electric generation customers, versus transportation to storage fields for injection (CPUC, 2001)."*

134. As cited previously, reports of leaks from Montebello abound. See, for example: http://articles.latimes.com/1985-10-03/news/hl-932_1_gas-storage and http://articles.latimes.com/1985-09-05/news/hl-24891_1_natural-gas-leak and http://www.dailynews.com/opinion/20160421/old-gas-leak-raises-new-questions-for-socalgas and http://www.allgov.com/usa/ca/news/controversies/puc_not_as_crazy_about_storing_natural_gas_under_cities_as_it_used_to_be?news=641689 (Accessed August 2017). See also Weatherwax, cited previously.

The decision approving Montebello's closure does not specify decommissioning costs. Rather, based on the decision and subsequent financial disclosures, it appears the removal and sale of cushion gas, sale of equipment and the land, was expected to produce a net gain for ratepayers and for the company. (Looking back at Decision 01-06-081, which approved the Montebello decommissioning, it looks like ratepayers and SoCalGas received a net gain).

SoCalGas closed another small gas storage field in Whittier in 1996. That field operated from 1952 until 1986. In 2001, SoCalGas was still recovering hazardous waste clean-up costs (SoCalGas, 2001).

Two other fields might be considered to have been retired. The first is known as the Ten Section field. Ten Section is about 10 miles from Bakersfield. It was discovered by Shell Oil in 1936. In 1953, SoCalGas, then known as Pacific Lighting Co., began a storage pilot program at the site. In 1977, PG&E and SoCalGas purchased the field from Shell for use as a gas storage facility. Storage operations continued until 1984, when PG&E and SoCalGas sold the field to McFarland Energy. At least two attempts have been made by the current owner to reestablish storage operations at the site but have not come to fruition. The latest resulted in the owner, Tricor, holding an open season seeking service subscriptions in 2009, and subsequently obtaining a CPCN from FERC to develop and operate the field.[135] Tricor intended 22.4 Bcf working inventory with a maximum injection rate of 800 MMcfd and withdrawal of 1,000 MMcfd (Wood, 2009). Tricor halted efforts to develop the project citing obstacles imposed by DOGGR (FERC, 2011). What effort SoCalGas undertook to close off the original pilot storage project is unknown. The industry rumor was that the field "leaked" and was the reason PG&E and SoCalGas sold it.

The second field was Coalinga Nose. This was a field that provided gas to PG&E until approximately 1987 or 1988. Coalinga Nose was owned jointly by Unocal, Texaco, Mobil, and Chevron. It was an operating oil field and Unocal injected natural gas to optimize the oil production. Reference is found to blowdown of the gas cap on the oil field beginning in May 1988. An old CGR would reveal how much gas PG&E received from Coalinga Nose, but as it was an oil field, it would not have been subject to approval of the CPUC to retire and abandon as a utility gas storage field (Starzer, et al., 1995).

135. The CPCN was granted in 2011 (FERC Docket No. CP-09-432-000). See presentation by Ryan Kunzi to Arizona Corporation Commission.

Appendix 2-10: Capital investments at storage facilities

PG&E and SoCalGas's FERC "Form 2" reports for each year from 1997, to 2016 show, among other things, annual capital investment and O&M expenses by asset class.[136] They do not, however, provide more descriptive information about the nature of the capital investment. Somewhat more about what the investment items included can be pieced together by reviewing rate case applications and CPUC decisions as to what regulators ultimately approved.

The Form 2 shows PG&E's O&M expense in recent years has averaged roughly $20 million per year. The capital expenditure (CapEx) is dominated by investment in the mid-2000's to build an additional pipeline connection from McDonald Island to its Bay Area Loop and backbone transmission, which was intended to preserve reliability should one of the other lines wash out (Line 57C). The expenditures average to a 6.1% compound annual growth rate for O&M and 6.4% for capital. (See Figure 27).

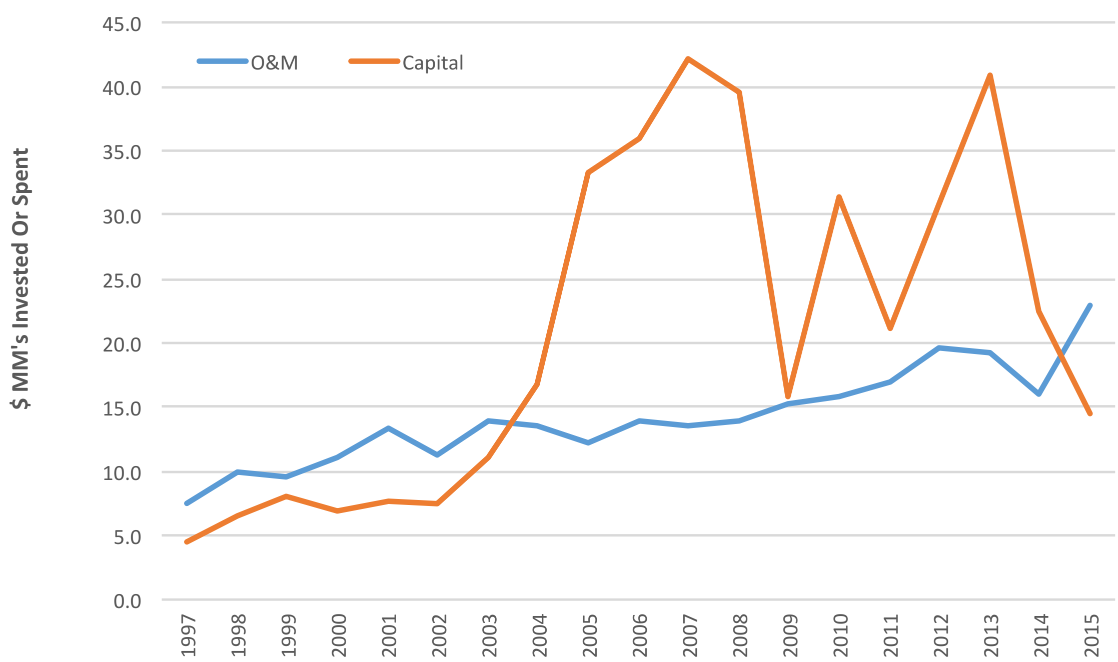


Figure 27. PG&E Reported CapEx and O&M for Storage.
Source: Aspen Environmental Group; FERC Form 2

136. The Form 2 is a standard report that FERC requires be filed by all jurisdictional pipelines. By virtue of the Hinshaw Exemption, PG&E and SoCalGas are not FERC-jurisdictional and are therefore not required to file Form 2's. They have filed the FERC Form 2 with the CPUC as a matter of practice.

Over the same years, SoCalGas spent much more in absolute terms, but its storage O&M grew at 2.3% while its capital expenditure grew at 2.9% (see Figure 28).

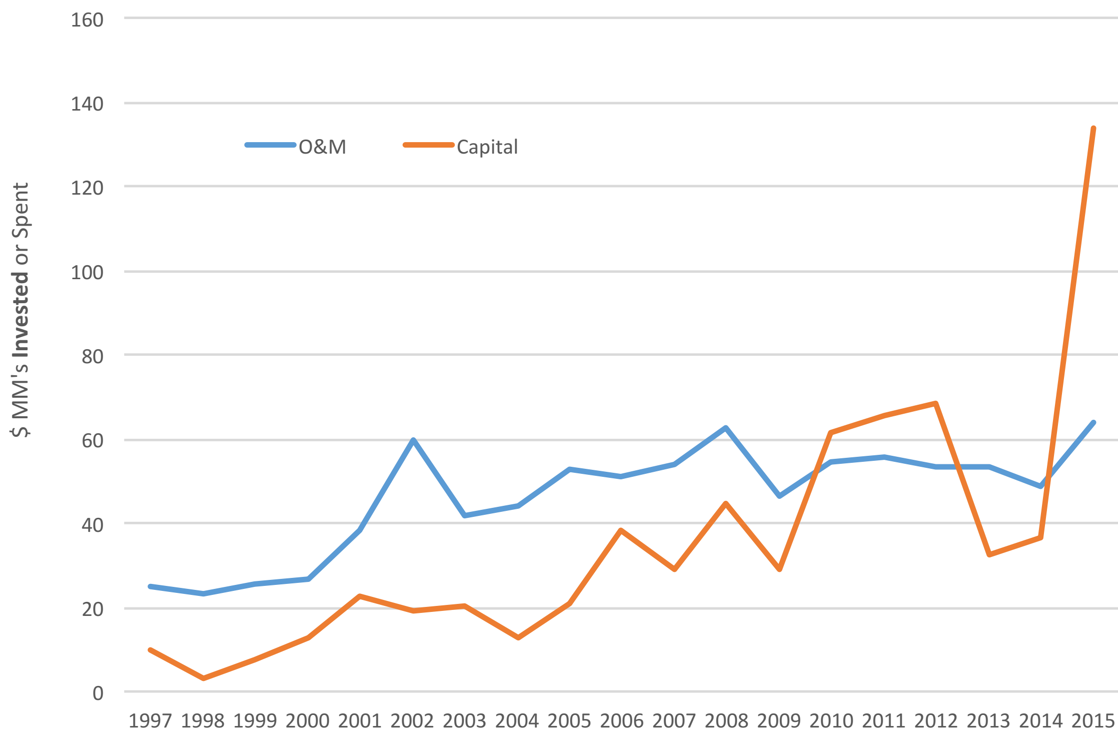


Figure 28. SoCalGas Storage Reported Capex and O&M.
Source: Aspen Environmental Group; FERC Form 2

SoCalGas's working inventory of 137 Bcf is much larger than PG&E's effective cycling capability of 40 Bcf.[137] Normalizing the O&M expense by Bcf of cycling capability, shown in Figure 29, shows the two utilities' spending on storage O&M to be generally similar.

137. PG&E began some years ago to describe its working inventory as much larger than 80 Bcf at McDonald Island, but only about half can functionally be cycled in a season. The CPUC used the smaller 40 Bcf in comparing the inventory of the two companies in Decision No. 15-06-004, p. 19. If the analysis used the larger 80 Bcf, then PG&E's per Bcf O&M would look much lower than SoCalGas'.

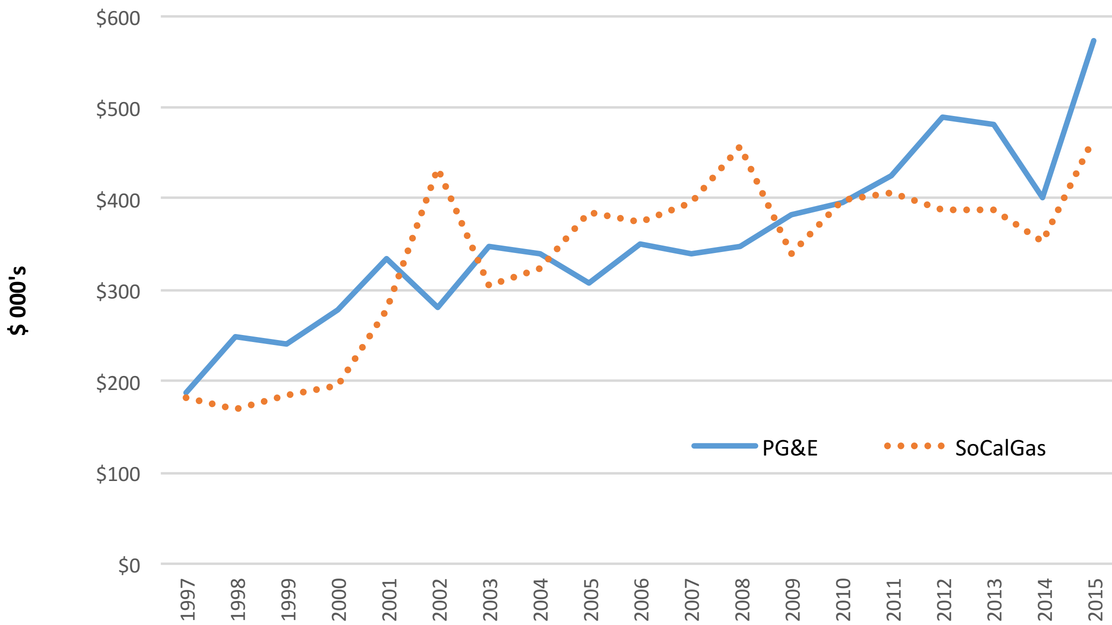


Figure 29. PG&E and SoCalGas Normalized O&M Expense for Storage.
Source: Aspen Environmental Group

While the Form 2 reports actual spending, a general rate case (GRC) is the regulatory proceeding in which a utility lays out what it proposes to spend for the next few years and obtains approval to recover those costs in rates. The CPUC uses a three-year cycle, so in 2014, SoCalGas filed its proposal to cover rates set for 2016, 2017, and 2018. PG&E's GRC is split between distribution versus transmission and storage. Its last Gas Transmission and Storage (GT&S) rate case was filed in 2013, decided in 2016, for rates effective in 2015, 2016, and 2017.[138] PG&E just filed a new GT&S case in November 2017.

In SoCalGas' last GRC (A. 14-11-002), SoCalGas described its storage department having 175 employees who operate the company's four storage fields and perform the maintenance, integrity, and engineering activities for them. It requested $40.2 million be approved in rates to cover O&M activities. The Office of Ratepayer Advocates (ORA) came in willing to support only $36.4 million. SoCalGas and ORA split the difference in settlement, adopted by the CPUC in Decision No. 16-06-054, which represented an increase of approximately 22%

138. Because the decision in the case came late, it authorized rates for 2018 as well. See CPUC Decision No. 16-06-056, p. 2

over 2014's recorded O&M costs (CPUC, 2016c). On capital expenditures ORA countered little on year 1 of the test period, and did not oppose the proposed spending at all for years two or three.

SoCalGas also proposed in the GRC to begin "a more proactive and in-depth approach for evaluating and managing the risks associated with the wells in [its] underground storage fields (CPUC, 2016d)." It would move away from the qualitative assessments based on operating experience in which well risk mitigation was conducted on a case-by-case basis, with actions to address problems when identified. The new approach would be a more robust and quantitative approach that would be more "proactive and in-depth" to capture "more information on the condition of our gas storage wells and develop models that will assist in prioritizing risk mitigation activities (SoCalGas, 2014b)." That prioritization would be "based on the location, age, condition and other factors." The storage integrity improvement program would last six years, after which future inspection and mitigation costs would "be addressed through routine operations (SoCalGas, 2014b)." SoCalGas appears to have had no comprehensive, proactive, long-term view of how to manage the condition of its storage fields; instead, it was in a reactive mode asking for permission to spend more on O&M after it detected problems. Most of the new storage integrity management program will be to gather data and build a decision model so that SoCalGas can prioritize maintenance activities according to an assessment of its biggest risks rather than continue to deal with issues as they arise.

PG&E, in its last GRC, "qualitatively assessed" its facilities as in "fair to good" condition (CPUC, 2013, A 13-12-012). PG&E has not yet made public any analysis behind its decision to retire Los Medanos and Pleasant Creek. With no public information available, one cannot say if the condition issues contributed to the decision or if the decision was based solely the cost of compliance with the new DOGGR rules (estimated at roughly $240 million per year, statewide).[139]

While the PG&E and SoCalGas storage spending is public via the Form 2 and rate cases, the independent storage assets in northern California charge market-based rates. They therefore do not file rate cases at the CPUC. No known public record of their O&M or capital expenditures exists. One might expect them to more carefully maintain their facilities because not having their costs embedded in the rate base means they obtain no revenue if they cannot operate. This has limits, though, because even their rates have a large reservation charge component to it within multi-year contracts. We do know that Central Valley and Gill Ranch are essentially brand new; Wild Goose and Lodi have been recently acquired and would have gone through due diligence review, which arguably would have

139. See Standardized Regulatory Impact Assessment, p. 38 available at http://www.conservation.ca.gov/dog/general_information/Pages/UGSRules.aspx. Accessed July 2017. It does not appear that this $238 million takes into account lost revenue potential from lower withdrawal capability although it does include $31 million per year for new wells. Whether those are observation wells or new withdrawal wells is unclear.

included some sort of condition assessment and a taking into account of that condition in the purchase prices as part of the acquisition process. The Standardized Regulatory Impact Assessment (SRIA) also opined that the newer facilities of the independents "may not require as much remedial work" and noted that in "some cases the requirements in these proposed regulations are already in place."[140]

A last bit of perspective on financial viability and storage investment may be helpful. The 2015 FERC Form 2 submitted by SoCalGas showed a total value of its storage-related gas plant in service at $833 million. Its April 2017 Form 10-K (A required annual report that provides a comprehensive overview of a company's business and financial condition and includes audited financial statements.) with the Securities and Exchange commission cited a net book value for Aliso Canyon alone of $531 million (which includes the $217 spent on the new compressor turbines, which will begin service should the facility start reinjection). That Form 10-K also reported net earnings for SoCalGas in 2016 of $349 million (and $419 million in 2015) (Sempra, 2016). Note 15 to its statement of financial condition noted that ~$700 million of its $1.2 to $1.4 billion in insurance has been spent. If they do not recover any of those costs it could have a significant impact on earnings. PG&E's FERC Form 2 shows a value on its storage assets of $667 million.

Financial information for the independent storage operators is again difficult to track down. We found that Lodi sold in 2014 for $105 million, far lower than the $440 million it had previously sold for in 2007 (Bowers, 2015). Gill Ranch's 2010 construction value for its 20 Bcf of inventory capacity was $225 million.[141] (Gill Ranch is set up so that 75% is owned by an LLC held by Northwest Natural, which also owns the Mist gas storage facility near Portland, Oregon. The other 25% is owned by PG&E.) When Brookfield Infrastructure acquired Wild Goose in 2015, it acquired all of Niska Gas Storage Partners (totaling 225 Bcf of inventory capacity, including several large facilities in Alberta in addition to Wild Goose itself) for $912 million.[142] Central Valley Gas Storage was developed by AGL Resources for $35 million (AGL Resources, 2014). With flat natural gas prices the independents may have more trouble attracting subscribers. Bloomberg cited low (and ostensibly flat) natural gas prices as causing a large decrease in the value of Niska Gas Storage, leading to a halt in distributions to shareholders and causing its owners to seek a sale.[143]

140. SRIA, p. 29

141. See https://www.sec.gov/Archives/edgar/data/1359055/000110465907055631/a07-19932_4ex99d1.htm (Accessed July 2017).

142. See https://www.pehub.com/canada/2015/6/brookfield-led-group-to-acquire-niska-gas-storage-for-912-mln/ and https://seekingalpha.com/filing/2857264 (Accessed July 2017).

143. See http://www.oilandgasinvestor.com/niska-gas-storage-partners-explores-sale-792161#p=full (Accessed July 2017).

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Chapter Three

How will implementation of California's climate policies change the need for underground gas storage in the future?

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ABSTRACT

California leads the nation in developing policies to address climate change, with a combination of economy-wide greenhouse gas (GHG) reduction *goals* policies (AB 32, SB 32, etc.) and complementary *means* policies that target specific sectors or activities, such as those that encourage energy efficiency, renewable electricity, electricity storage, etc. California also has a cap and trade program to provide an economically efficient framework for reaching emission targets. Chapter 3 is charged with examining how implementation of these policies will affect the need for underground gas storage (UGS), focusing on the years 2030 and 2050 as key policy milestones. The need for UGS derives from many different kinds of demands for natural gas, which can primarily be organized into two categories: building and industrial heat, and electricity generation. (A third category, vehicle fuel, plays an extremely minor role in today's energy system.) Depending on end use, temporal variation in gas demand can vary from subhourly to seasonal time scales, and it is the temporal variations that have the greatest influence on the demand for UGS. California's climate policies will change both the quantity of gas used for these purposes and their temporal profiles, and both of these will change the need for UGS, but not necessarily in the same direction. Understanding the net impact on UGS of changes to the energy system designed to meet climate goals requires having information not only about the time of gas use during the day (diurnal variation), but also how the demand for gas might vary on multiday to seasonal time scales.

None of California's climate policies specify the end-state energy system that would reliably meet California's energy needs as well as the emission goals, largely because maintaining the reliability required for societal well-being and the economy will become more challenging with increasingly aggressive emission goals. Natural gas currently provides the primary method for backing up renewable energy in California. If this does not or cannot

change, natural gas (or other energy-dense fuels with lower net GHG emissions, such as biomethane or hydrogen) could remain an important part of our energy system for some time. On the other hand, it may be possible to reduce or even eliminate the need for gas combustion and therefore the need for gas storage with a combination of technical advances, efficiency mandates, and regionalization. California needs to vet these alternative ideas for maintaining reliability. Until another option can be demonstrated to work, gas cannot be ruled out as part of a future energy system that has extensive intermittency.

3.0. INTRODUCTION

The purpose of this chapter is to answer the question: How will implementation of California's climate policies change the need for underground gas storage in the future? From Chapter 2, we have made it clear that alternatives to UGS exist, but they are likely to be expensive. In Chapter 3, we examine the future need for the gas reserve services currently provided by UGS. UGS can rapidly store or deliver gas to meet periods of peak gas demand during certain hours of the day in certain seasons. Although we use the term UGS, these services could theoretically be provided by the alternatives to UGS discussed in Chapter 2.

This chapter examines the impact that California's climate policies may have on the need for gas reserve services as explicitly requested by legislation. California leads the nation in developing policies to address climate change. Perhaps the most fundamental of these policies requires that California reach greenhouse gas (GHG) emission goals in 2020, 2030, and 2050. Based on AB 32, California is required to reduce GHG emissions to the 1990 level in 2020. SB 32 requires California to further reduce its GHG emissions to 40% below the 1990 level by 2030. Finally, Governor Schwarzenegger's Executive Order E-3-05 and Governor Brown's Executive Order B-30-15 both require the state to reduce GHG emissions to 80% below the 1990 level by 2050. These policies codify energy system *goals*.

California also has a number of complementary climate policies, such as those that encourage energy efficiency, renewable electricity, electricity storage, emissions limits from long-term power purchase agreements, biofuels, increases in electricity and hydrogen for transport, and decreases in short-lived greenhouse gas emissions (such as methane). California also has a cap and trade program to provide an economically efficient framework for reaching emission targets. These policies codify specific *means* to move towards the energy system goals. Appendix 3-3: Recent Federal and State Policies, lists all relevant policies, including California *goals* and *means* policies.

Since we expect that the amount of gas California will use in the future will change, because of these climate policies, it is reasonable to ask how implementation of these policies will affect the need for UGS. The need for UGS derives from many different kinds of demands for natural gas, which can primarily be organized into two categories: building and industrial heat, and electricity generation (with a third category, vehicle fuel, playing an extremely minor role in today's energy system):

- In the building and industrial heat category, different temporal profiles of gas demand are currently driven by: (1) High capacity factor or "baseload" demand (roughly constant demand at all hours and seasons); (2) Daily peak demand due to human patterns of use (morning and evening peaks); (3) Seasonal peak demand, which primarily occurs during winter mornings and evenings due to hot water and space heating; and (4) During emergencies such as cold weather events, when heating use may increase markedly.

- In the electricity category, temporal profiles of gas demand are currently driven by (1) High capacity factor or "baseload" demand (roughly constant demand at all hours and seasons); (2) Daily peak demand due to human patterns of use (morning and evening peaks); (3) Seasonal peak demand, generally occurring during summer months in the late afternoon as a result of air conditioning, with peaks occurring in September; (4) Increased balancing of intermittent renewable generation (which can occur on time scales ranging from subhourly to seasonally, and in particular for growing solar capacity, steep changes in gas use occur daily around 8 a.m. as solar generation increases, and again at 4 p.m. as it wanes); and (5) During emergencies such as wildfires, which may disable electric transmission lines.

In all these cases, there is a natural gas demand, but the demand for UGS is not necessarily the same. Strategies available for both electricity and non-electricity demand to increase flexibility in gas use, such as demand response, energy storage, regional coordination, etc., will be affected by the temporal patterns of gas use, as well as the costs, capacities, durations, and ramping speeds of the strategies.

California's climate policies will change both the quantity of gas used for these purposes and their temporal profiles, and both of these will change the need for UGS, but not necessarily in the same direction. For example, more intermittent renewable electricity will replace gas that we use for electricity generation. But more intermittent electricity means that UGS requirements will likely increase, in order to provide reliable ("firm") electricity generation when intermittent electricity output (primarily wind and solar) is low. Energy storage devices such as batteries can help with this problem, but decreased output lasting many days as a result of weather events might increase the use of gas. Meanwhile, even if we use less gas overall, the peak use of gas might not decrease, or could even increase. Understanding the net impact on UGS of changes to the energy system designed to meet climate goals requires not only having information about the time of gas use during the day (diurnal variation), but also how the demand for gas might vary on multiday to seasonal time scales. This is discussed in detail later in this chapter.

Our methodology consists of a review of available literature on future energy scenarios under different greenhouse gas emission pathways, followed by an expert synthesis of available scenarios focusing on 2030 and 2050, two key compliance years for greenhouse gas emissions. A wide variety of scenarios have been developed to explore options for meeting California's climate goals. These mirror the two types of climate policies the state currently has. Scenario studies develop alternative energy systems that meet the overall climate policy *goals*. These studies provide ranges for the amount of possible gas use in the future, constrained by having an energy system that reliably meets our needs. They do not, however, generally include information about the time of use of gas, nor factor in seasonal variation in either renewable electricity output or gas use.

A second kind of study projects the impacts of specific *means* policies designed to move California towards the climate goals. These studies do project the time of use of electricity and/or gas, but do not, in general, ensure that the energy system as a whole works to reach the overall emissions goals. For example, researchers have concluded that it will be necessary for the electricity system to reduce emissions more than its "fair share," because transportation is more difficult to de-carbonize (Williams et al., 2012). Such system-wide adjustments cannot be easily computed in a model that studies electricity or transportation alone.

Finding: We found no studies that comprehensively assess the volumes of gas needed in the future, i.e., studies that construct complete future possible energy system configurations that meet the climate goals, project the impact of the policies that provide the means to reach these goals, and project the time of use of gas and electricity on every time scale from subhourly to seasonally.

Given the studies that do exist, this chapter takes two different approaches. We looked at scenarios for different models of meeting these long-term *goals* on a system-wide basis and, where possible, inferred their impact on the need for UGS. In general, these studies tell us that the need for UGS may decrease, but it could as well increase. Secondly, we looked at projections of hourly gas demand in 2030 based on implementation of the *means* policies.

Conclusion 3.1: There are no energy assessment studies that can convincingly inform the future need for UGS in California, because greenhouse gas emissions goals and expectations for energy system reliability remain to be reconciled.

Recommendation 3.1: California should commission or otherwise obtain studies to identify future configurations of energy system technologies for the state that meet emission constraints and achieve reliability criteria on all time scales from subhourly to peak daily demand to seasonal supply variation. These studies should result in a new hybrid forecasting and resource assessment tool to inform both policy makers and regulators.

3.0.1. Assessment of Energy Technologies

Our assessment of future energy scenarios for California was informed by a detailed assessment of current and potential future energy technologies, found in Appendix 3-2: Energy Technologies. A list of technologies included in that assessment is shown in Table 1.

Table 1. Energy technologies considered in this chapter.

Wind energy	**Energy storage**
Conventional wind power	Battery storage
Floating offshore wind turbines	Thermal storage
High-altitude wind	Pumped hydroelectric storage
Solar energy	Compressed air energy storage
Solar photovoltaics	Other electromechanical technologies
Solar thermal	**Natural gas substitutes**
Geothermal energy	Biomethane
Conventional geothermal energy	Hydrogen
Enhanced geothermal systems	Synthetic natural gas
Supercritical geothermal systems	**Power-to-gas**
Hydropower	Power-to-gas hydrogen
Conventional hydropower	Power-to-gas methane
Marine and hydrokinetic power	**Vehicle fuel shifting and electrification**
Nuclear power	Electric vehicles
Conventional nuclear power	Hydrogen vehicles
Small modular reactors	Natural gas vehicles
Carbon dioxide capture and sequestration	**Building electrification**[a]

a While buildings are already partially electrified, the term "building electrification" here refers to replacing fuel combustion devices (e.g., furnaces, water heaters, clothes dryers and cooking appliances) with electric-based technologies. While all technologies can utilize resistive heating, these tend to be inefficient and less dynamic. For space heating, water heating, and clothes drying, heat pumps can be used, and have efficiencies many times higher than combustion-based technologies. For cooktops, infrared heating or magnetic induction can be used as effective substitutes for natural gas combustion. For higher-temperature applications, a variety of other technologies are also possible, including induction, radio frequency, microwave, infrared, ultraviolet, and plasma heating (Greenblatt et al., 2012)

3.0.2. Recent California and Federal Policies

In addition to reviewing the literature for GHG-compliant scenarios, we also took into consideration all recent California policies bearing on future GHG emissions. For example, policies with among the largest GHG impacts are the economy-wide GHG targets for 2020 (AB 32), 2030 (SB 32 / AB 197) and 2050 (Executive Order S-3-05 and B-30-15), renewable electricity and building efficiency targets (SB 350), as well as the recent extension of cap and trade policy to 2030 (AB 398). Since California meets or exceeds federal GHG policies in almost every area, our analysis was limited to a small number of federal policies. All relevant policies are summarized in *Appendix 3-3: Recent Federal and State Policies*.

3.0.3. Literature Review of Greenhouse Gas Scenario Studies

We examined 26 studies, with 12 covering California, 12 covering the U.S., and three with global scope. While most of the studies covered all sectors, two only examined the electricity sector, one just modeled transportation, and one only examined gas use. These latter two types of scenarios, while of less value because they did not cover all sectors that used natural gas, did provide complementary information. Studies examined are summarized in Table 2.

Note that none of these studies looked at the amount of UGS needed, or even subannual demand for natural gas—a key driver of the need for UGS. Nonetheless, the scenarios did provide additional information, e.g., the presence (or in some cases, quantities) of electricity storage, flexible loads, building and vehicle electrification, renewable electricity generation, low-carbon gas, and so on, that help provide a more complete picture of how the combined electricity-plus-natural gas system could change. This information, together with complementary data from other sources and our own expert judgment, was used to estimate the future impact on gas storage reserve capacity needs compared with today's use.

Table 2. List of studies consulted for future gas demand projections.

Reference(s)	Short title	Spatial coverage	Sectors	Years covered	Number of scenarios
Greenblatt et al., 2011; Greenblatt and Long, 2012	California's Energy Future	CA	All	2050	51 (only 17 used)
Williams et al., 2012	Pivotal Role of Electricity	CA	All	2050	5
McCollum et al., 2012	Deep GHG Reduction Scenarios	CA	All	2050	2
Wei et al., 2013a	Deep Carbon Reductions in CA	CA	All	2050	4 (+ 8 only electricity)
Wei et al., 2013b; Nelson et al., 2013	Scenarios Meeting CA 2050 Goals	CA	All	2030 (elec. only), 2050	4 (+14 only electricity)
Yang et al., 2014	Modeling Optimal Transition Pathways	CA	All	2050	12
Yang et al., 2015	Achieving 80% GHG Reduction	CA	All	2050	6
Greenblatt, 2015	Modeling CA Policy Impacts on GHG	CA	All	2030, 2050	4
E3, 2015a	PATHWAYS: Long-term GHG Reduction Scenarios	CA	All	2050 (2030 for one scenario)	8
E3, 2015b	Decarbonizing Pipeline Gas	CA	All	2050	3
CA Utilities, 2016	California Gas Report	CA	Gas only	2030 (analysis to 2035)	2
CARB, 2017a	Scoping Plan Update	CA	All	2030	3
RMI, 2011	Reinventing Fire	US	All	2050	2 (+ 4 only electricity)
Lin et al., 2013	Hydrogen Vehicles	US	Transport	2050	16
Logan et al., 2013	Natural Gas Scenarios in U.S. Power Sector	US	Electricity	2030, 2050	8
Williams et al., 2014	Deep Decarbonization	US	All	2050	5
Clarke et al., 2014	Results of EMF 24	US	All	2050	30
Fawcett et al., 2014	Overview of EMF 24	US	All	2050	7
EIA, 2014	Annual Energy Outlook 2014	US	All	2030, 2040	30

Reference(s)	**Short title**	**Spatial coverage**	**Sectors**	**Years covered**	**Number of scenarios**
OECD/IEA, 2015	World Energy Outlook	US, Global	All	2030, 2040	3
Risky Business Project, 2016	From Risk to Return	US	All	2050	5
White House, 2016	Mid-Century Strategy	US	All	2035, 2050	6
Cole et al., 2016	Deep Decarbonization	US	Electricity	2030, 2050	24
EIA, 2017a	Annual Energy Outlook 2017	US	All	2030, 2050	8
McJeon et al., 2014	Decadal-Scale Climate Change	Global	All	2030, 2050	10
Shell Oil, 2016	Pathways to Net-Zero Emissions	Global	All	2100	1
	TOTAL				251 (217 used)

The temporal scope of all studies extended at least until 2030. For 21 studies, the scope extended until 2050 (one study by Shell Oil extended until 2100, but contained no information about the intervening years, so was only minimally useful).

In addition, Bartos and Chester (2015) and Greenblatt et al. (2017a) did not contain quantitative data on natural gas use, but were nonetheless useful and contributed to our overall understanding by providing information on how climate change might affect the supply of, and demand for, energy in 2050.

For all the studies, we extracted any data pertaining to natural gas use. In most cases, only annual gas demand was reported. We also inferred how the use of natural gas would change on time scales shorter than annual (e.g., monthly and hourly), based on reported information such as the capacity of electricity storage, demand response/load-shifting, electric vehicle charging, etc. However, not all studies provided this information quantitatively; in many cases, we had only qualitative indications of the presence or absence of such capabilities.

Where available, we also noted the amounts of biomethane, synthetic natural gas (SNG), hydrogen, and CO_2 sequestration present in the scenarios, all of which could have an impact on required UGS in general. While biomethane, SNG, and small amounts of hydrogen can in principle be blended with conventional natural gas in the existing pipeline network, pure hydrogen (e.g., dedicated for use in vehicles) as well as CO_2 destined for underground sequestration cannot be blended with conventional natural gas and must be managed with separate pipeline networks. It was important to understand when such demands were present, as it affected how much of existing natural gas infrastructure capacity may need to be retained for these services, even if the amount of conventional natural gas used diminishes.

We divided the examined scenarios into two approximate categories: “GHG compliant” and “non-GHG compliant.” GHG compliance means meeting California’s 2030 and 2050 GHG reduction targets (of 40% and 80% below the 1990 level, respectively, via SB 32 and Executive Order S-3-05). While not all scenarios modeled California, we categorized a scenario as GHG compliant if its relative economy-wide GHG emissions fell to a level comparable to California’s GHG targets. The non-California studies were useful to examine how the same climate objectives were applied to different—but similar—energy systems. Note that, in some cases, we had to use a base year that was different from 1990 in order to estimate this GHG reduction. As a result, the categorization was somewhat qualitative given the imprecision of normalizing to different base years.

Altogether, we identified a total of 322 natural gas demand estimates across the 26 studies. Of these, 88 estimates (for 2030 and/or 2050) represented GHG-compliant scenarios. For California scenarios that included all energy sectors, there were a total of 30 demand estimates: eight for 2030 and 23 for 2050, spanning nine studies and 26 individual scenarios. Additional data were available for GHG-compliant scenarios for the entire U.S.:

30 demand estimates encompassing all energy sectors, and 25 for the electricity sector. An additional 223 demand estimates corresponded to scenarios that were not GHG compliant: 46 for California, 171 for the U.S., and six for the world.

3.1. ELEMENTS OF A FUTURE CALIFORNIA ENERGY SYSTEM

Based on our review of the literature, scenarios that meet California's 2050 climate goal all contain significant increases relative to today in several elements of the energy system:

- Increased energy efficiency in all sectors, somewhat moderating demand increases from population and economic growth, as well as the magnitude of some demand peaks
- Increased transportation electrification (portions of light- and heavy-duty vehicles)
- Increased renewable electricity generation (primarily wind and solar)
- Increased electricity storage and flexible electric loads

In addition, some scenarios employ significant implementation of:

- Fossil fuel with CO_2 capture and sequestration (CCS) in electricity generation (and to a limited extent, industrial facilities)
- Flexible, non-fossil electricity generation: nuclear, geothermal, biomass with or without CCS, marine/hydrokinetic technologies, solar thermal with storage, etc.
- Building electrification in residential, commercial, and possibly industrial sectors
- Low-carbon gas production: biomethane, SNG, and/or hydrogen blended in pipelines[1]
- Pure hydrogen production, used in vehicles and possibly other sectors
- Power-to-gas (P2G): load-balancing technology that converts excess electricity into hydrogen and/or methane, typically for direct pipeline injection

1. Here "low-carbon" refers to net GHG emissions, not just the emissions encountered when the gas is burned. Both biomethane and SNG, while chemically identical to natural gas-derived methane, have the potential to be much lower in net GHG emissions than natural gas, though for both SNG and hydrogen, the source of CO_2 can make a critical difference to net emissions. See Appendix 3-2: Energy Technologies, Natural Gas Substitutes for more information.

- Increased regional electricity transmission capacity to allow more imports of out-of-state resources (particularly renewables) to help smooth supply-demand imbalances. California policy counts the GHG emissions from out-of-state generation in its GHG inventory (CAISO, 2016a; ICAP, 2017), so high-GHG generation resources would have to be used very sparingly.

While many of these elements play prominent roles in 2050 in most scenarios, they are more subdued or not even present in 2030. As a result, the scenarios we examined did not start to diverge significantly in terms of their potential impact on UGS until after 2030.

3.1.1. Balancing Gas Demand on Multiple Time Scales

In Chapter 2, we learned that there are seven distinct functions of UGS in California:

1. Storage provides supply when, in some years, monthly winter needs exceed the pipeline capacity.

2. Storage compensates for relatively constant rates of gas production that do not match variation in gas demand.

3. Storage provides supply when winter peak day demands exceed pipeline capacity.

4. Storage provides inter-day balancing to support hourly changes in demand that the receipt point pipelines cannot accommodate. This service is essential in allowing the flexible use of gas-fired electricity generators to back up renewable generation.

5. Storage provides in-state stockpile of supply in case of upstream pipeline outage or other emergency such as wildfires.

6. Storage allows savings through seasonal price arbitrage (winter prices are usually, but not always higher than summer prices).

7. Storage grants marketers a place to hold supply and take advantage of short-term prices for liquidity and short-term arbitrage.

Of these, possible changes aimed at reducing GHG emissions in California's energy system would most strongly affect items 1, 3 and 4: meeting winter demand, daily peak demand and daily balancing. Changes to the energy system in response to California's climate policies could have a secondary effect on the need for stockpiling depending on whether the net effect results in an increase or decrease in gas demand. Short- and long-term price arbitrage represent secondary functions of underground storage to begin with and technology changes will not likely change this.

Finding: Sub second (frequency regulation) electricity storage can be provided by flywheels or fast-response batteries; response times of minutes to hours and storage capacities of several hours can be provided by thermal storage at the building or power plant, battery storage, and pumped hydroelectric or compressed air energy storage. Flexible load capacity and management of regional transmission capacity are other tools with similar response times to storage that can be called upon for multiple hours at a time.

Conclusion 3.2: Various forms of energy storage could perform intraday balancing, i.e. manage changes in gas demand over a 24-hour period.

As discussed in Chapter 2, the most cost-effective technologies for long-duration (multiple-day) electricity storage are pumped hydroelectric storage (PHES) and compressed air energy storage (CAES). However, PHES needs very specific siting characteristics and is typically problematic because of its impacts on local ecosystems (stoRE, 2013). An exception to this may be closed-loop systems that do not affect existing bodies of water (e.g., the Eagle Mountain pumped storage project near Palm Springs, CA; Eagle Crest Energy, 2016). CAES also requires specific geology to avoid high-cost aboveground storage, and is usually a hybrid system that requires fuel (typically natural gas) when air is withdrawn from storage (Akhil et al., 2013). Therefore, unless the fuel is itself very low-carbon, CAES is not a GHG-free technology. Adiabatic CAES has been proposed to avoid this limitation, but thus far only one 500 kW demonstration plant in Switzerland has been built (the Pollegio-Loderio Tunnel ALACAES Demonstration Plant) (SNL, 2016).

Battery storage is currently more expensive, but costs continue to fall rapidly as markets and technologies mature; for more information, see Electricity Storage in Chapter 2 or Energy Storage in *Appendix 3-2: Energy Technologies*. Batteries can also charge or discharge more quickly than PHES and CAES, and are therefore suitable for short-duration (intrahour) storage, but multiple day (and certainly seasonal) storage capacity would be prohibitively expensive. Flywheels and other electromechanical technologies have also been explored for very short-term (subseconds to minutes) storage, but they are still very expensive relative to incumbent natural gas turbine technology (Akhil et al., 2013).

Finding: Most forms of energy storage as currently conceived will probably be inadequate for managing daily peak demand that can occur over multiple days and seasonal demand imbalances.

With the exception of PHES technologies, storage tends to be designed with capacities of no more than 48 hours (see Energy Storage in *Appendix 3-2: Energy Technologies*). Only a handful of PHES facilities worldwide have been built with storage capacities greater than 48 hours, and only two are located in the U.S. (Grand Coulee in Washington, at 80 hours, and San Luis in California, at 298 hours) (SNL, 2016). Additional PHES capacity may be available in California and elsewhere in the U.S. (see Appendix 3-2: Energy Technologies, *Pumped Hydroelectric Storage*), but total new capacity in California is ~2.3 GW, much less than the ~30 GW of generation capacity that may occasionally be needed by 2030 to shore up intermittent renewables (see discussion in Section 3.2.4. Gas Needed to Back Up

Intermittent Renewables). Moreover, "current market structures and regulatory frameworks do not present an effective means" of expanding PHES capacity in the U.S. (NHA, 2014, p. 3). PHES also faces environmental siting barriers and a challenging regulatory approval timeline that could take up to five years to license and an additional 10 or more years to construct. The National Hydropower Association concludes that "Policy changes are needed to support the timely development of additional grid-scale energy storage" including PHES (NHA, p. 3).

As discussed in the sections that follow, both wind and solar, which could become significant or even dominant forms of electricity generation in many future scenarios in California, experience considerable seasonal variation in output, as well as shorter-term (but still multiple-day) fluctuations resulting from weather events that are sometimes correlated across large regions, affecting total statewide (and possibly out-of-state) renewable generation capacity. The economics of storage for periods of lower frequency than intraday are much more challenging at present. Moreover, the hourly variations in wind and solar outputs may not be well matched to future electricity demand, requiring other forms of generation to serve as backup.

3.1.2. Energy Storage in Chemical Fuels

Chemical energy storage of low-carbon gases presents the most likely way to address inadequate generation capacity over long (multiple days to seasonal) durations. This includes:

- Biomethane, which is chemically equivalent to the methane found in natural gas, and can be produced from biogas with very low net GHG emissions. It can be blended with ordinary pipeline natural gas, but must still be managed using UGS. Note there are also limitations to the amount of biomethane that can be produced both inside and outside of California; see Appendix 3-2: Energy Technologies, *Biomethane*.

- Synthetic natural gas (SNG) which is also identical to the methane in natural gas, but can be produced from fossil fuels, biomass, or electrolysis of CO_2 and water. If produced from fossil fuels, the CO_2 that is also produced must be captured and stored via CCS to avoid high GHG emissions. This introduces its own pipeline and storage challenges (see Appendix 3-2: Energy Technologies, Carbon Dioxide Capture and Sequestration), and net GHG emissions may still not be sufficiently low to justify its widespread use. If SNG is produced from biomass, it could be expensive to manufacture, but has the advantage that the CO_2 produced does not need to be captured and stored to achieve low net GHG emissions. If SNG is produced directly from CO_2 and water, the CO_2 must be captured from a low-GHG source, and if provided directly from the atmosphere or ocean, it could be energy-intensive and expensive to produce (see Appendix 3-2: Energy Technologies, Power-to-gas methane).

- Hydrogen, like SNG, can also be produced from fossil fuels, biomass, or water electrolysis. While CO_2 captured from fossil fuels can eliminate GHG emissions from hydrogen production, it must still be managed via a pipeline and storage system. The hydrogen itself, whether blended with natural gas or used directly, must also be stored, using either dedicated hydrogen storage or conventional UGS. For more information, see Appendix 3-2: Energy Technologies, *Hydrogen*.

One example of the use of these low-carbon fuels for managing excess electrical generation capacity is "Power to Gas" or P2G, producing either hydrogen or methane (see Appendix 3-2: Energy Technologies, Power-to-Gas). This can be invoked whenever more electricity is generated than is needed, which often arises for intermittent renewables, though there may be circumstances where dispatchable generation (fossil-CCS, nuclear, geothermal, biomass, etc.) continues to operate for economic reasons, producing excess electricity.

Finding: P2G uses electricity from low-GHG generation technologies to make a substitute chemical fuel. However, similar to natural gas, these chemical fuels require transportation and storage.

Conclusion 3.3: The only currently available means to address multiday or seasonal supply-demand imbalances without using fossil natural gas appears to be low-GHG chemical fuels. These solutions have the same storage challenges as natural gas and may introduce new constraints, such as the need for new, dedicated pipeline and storage infrastructure in the case of hydrogen or CO_2.

3.1.3. Wildfires

Another issue is that of wildfires, which have long been a concern in the western U.S. and California in particular. Every year, thousands of acres of forests in California and elsewhere burn, mainly in summer months; for instance, there were 2,900 fires burning on 106 square miles across California in July 2017, more than twice last year's average (May, 2017). When fires occur, they sometimes force electric transmission lines offline (e.g., WECC, 2002; CAISO, 2002, 2003, 2007, 2008; CPUC, 2008; FERC, 2013), which can cause sudden loss of generation capacity and may last many days, similar to the intermittency occasionally experienced by wind and solar generation. These losses hamper the State's ability to provide adequate power to load centers, particularly during the peak electricity demand season. Moreover, wildfires often occur during hot weather, when the demand for air conditioning-driven electricity is highest. This combination of factors increases the reliance on backup strategies to provide local generation and, when necessary, load curtailment. There is some evidence that wildfire extent may be increasing with climate change (e.g., U.S. EPA, 2016).

3.1.4. Climate Change

According to Greenblatt et al. (2017a), climate change in California by 2050 is projected to result in changes to energy demand, with milder winters decreasing the use of energy for heating in buildings, and hotter summers increasing the use of electricity for air conditioning. Overall electricity demand would increase 0.8-4.3%, with peak demand increases of 2.0-4.2%.

Across the western region (Bartos and Chester, 2015), generally hotter temperatures would also result in:

- Decreased efficiency of thermal power plants: 7.4-9.5% (fossil-CCS, nuclear, geothermal, biomass, even concentrating solar)
- Decreases in gas combustion turbine capacities: 1.4-3.5%
- Decreases in solar photovoltaic (PV) generation: 0.7-1.7%
- Increases in wind generation: up to ~2.2%
- A negligible impact on hydroelectric generation
- Decreases in electric transmission capacity
- Extreme heat and drought may increase under climate change, exacerbating these effects

Finding: In California (assuming a similar mix of electricity generators as today) climate change could cause a reduction in generating capacity of 2.0-5.2% in summer, with more severe reductions under ten-year drought conditions (Bartos and Chester, 2015). Considered altogether, peak demand for electricity generation could increase by 10-15% in 2050 (Greenblatt et al., 2017a).

Conclusion 3.4: Climate change would shift demand for energy from winter to summer, reducing peak gas demand from reserve capacity in winter, but increasing it in summer. Decreases in electric transmission and generation capacity would increase reliance on backup generation and hence UGS, particularly in summer. The net effect would be a stronger reliance on UGS in summer, and possibly increased gas use, than in a scenario without climate change.

3.1.5. Role of Hydrogen

Pure hydrogen might play a more central role in the future by substituting for vehicle electrification, providing an alternative low-carbon energy pathway to replace petroleum fuels. Currently, electric vehicles appear to be on a rapid growth trajectory, and the State is pursuing an aggressive policy of vehicle and charging infrastructure expansion. However, it also supports growth of hydrogen vehicles, and breakthroughs could make this technology more desirable in the future. Some of the scenarios (E3, 2015a) discussed below invoke significant amounts of hydrogen by 2050 (~20% of 2015 total gas demand). If this occurs, the role of UGS could change if hydrogen is transported and stored in pure form, rather than mixed with natural gas. Like CO_2, hydrogen would require its own pipeline and storage infrastructure to safely handle the gas. However, it is also possible that hydrogen could be produced locally from electricity or biomass, obviating the need for dedicated hydrogen infrastructure. We consider both possibilities in our analysis.

3.1.6. Scenario Elements That Informed the Evaluation of UGS

In evaluating scenarios, we paid attention to the following elements:

- Annual demand for natural gas
- Seasonal and diurnal changes in non-electricity and electricity natural gas demand
- Seasonal and diurnal changes in electricity generation from intermittent renewables
- Seasonal and annual forecast flexible electricity generation capacity
- Annual electricity generation provided by intermittent sources (solar and wind)
- Annual electricity generation provided by CCS and flexible non-fossil resources
- Amount of electricity storage and flexible demand resources
- Shares of vehicle and building electrification
- Share of natural gas vehicles
- Share of natural gas provided by low-carbon sources (biomethane, SNG, hydrogen)
- Demand for pure hydrogen

While not all of this information was available, we attempted to gather as much of it as possible from diverse sources in order to arrive at a coherent picture of how changes in California's energy system could impact UGS.

3.2. DEMAND FOR UGS IN 2030

Finding: For the scenarios available in the literature, and with some minor exceptions (see below), changes to the energy system from the current state to 2030 are modest.
The variation in total annual demand for natural gas in 2030 ranged from between 78% and 100% of current levels in the six GHG-compliant studies we reviewed.

Additional scenarios that we did not include in our analysis were Greenblatt's (2015) S3 (60% of today's natural gas demand) and CARB (2017a)'s Scoping Plan Alternative (66% of today's natural gas demand). These scenarios were eliminated because they contained multiple extensions of existing policy goals that, while perhaps reasonable in isolation, we considered to be unrealistic when implemented simultaneously by 2030.[2] Moreover, for the CALGAPS S3 scenario (Greenblatt, 2015), emission reductions exceeded the 2030 target.

3.2.1. Non-electricity Gas Demand

Finding: Among the scenarios included, we found that, by 2030, total non-electricity natural gas demand would decrease by 11-22% relative to today, mainly due to efficiency improvements in the building stock.

Efficiency improvements reduce the need for gas for heating throughout the year; see Figure 1. Building electrification does not contribute substantially to this reduction by 2030 (though it could play a larger role by 2050). However, it is the peak gas use that determines the need for storage, not the total, and this peak occurs during cold days in the winter. Currently, the pipeline capacity to meet this peak could fall short by as much as 4,300 MMcfd. None of the scenarios we reviewed addressed peak gas demand in enough detail to quantitatively assess the need for UGS. However, if we assume efficiency improvements

2. Among the measures we considered to be unrealistic in CARB's Scoping Plan Alternative were (comparisons to current policies coming from CARB, 2017a): 60% renewable electricity generation (compared with ~27% today and 50% statewide target in 2030), 2.5 times baseline building efficiency improvements (compared with SB 350 goal of twice the historical rate through 2030, which is already challenging), increased building electrification (no building electrification is required by current State policy), early retirement of HVAC equipment (likely not cost-effective), 25% reduction in fuel GHG intensity (low-carbon fuel standard currently requires 10% reduction by 2020, and 18% by 2030), 4.7 million ZEVs deployed (State policy is 1.5 million by 2025, and 4.2 million by 2030), early retirement of 1 million vehicles (likely not cost-effective), increased reductions in vehicle miles traveled (VMT) (current Mobile Source Strategy goal is 15% reduction in light-duty vehicle VMT by 2050), and industrial sector GHG emissions reductions of 25% (and 30% in the refinery sector; current State policy goal is 20% refinery sector reduction by 2030). Many of these measures were also present in the CALGAPS S3 scenario, and in addition included: relicensing of the State's two nuclear reactors, increased high-speed rail deployment, an accelerated phase-out of hydrofluorocarbons, and reconversion of pasture to forest land to increase carbon sequestration. While many of these measures may indeed be realistic to implement after 2030, we were concerned about their expected speed of implementation in the nearer term.

reduce the peak proportional to the reduction in total use, then peak non-electricity demand for natural gas in winter could decrease by ~600-1,200 MMcfd, which is not enough to eliminate the need for UGS.

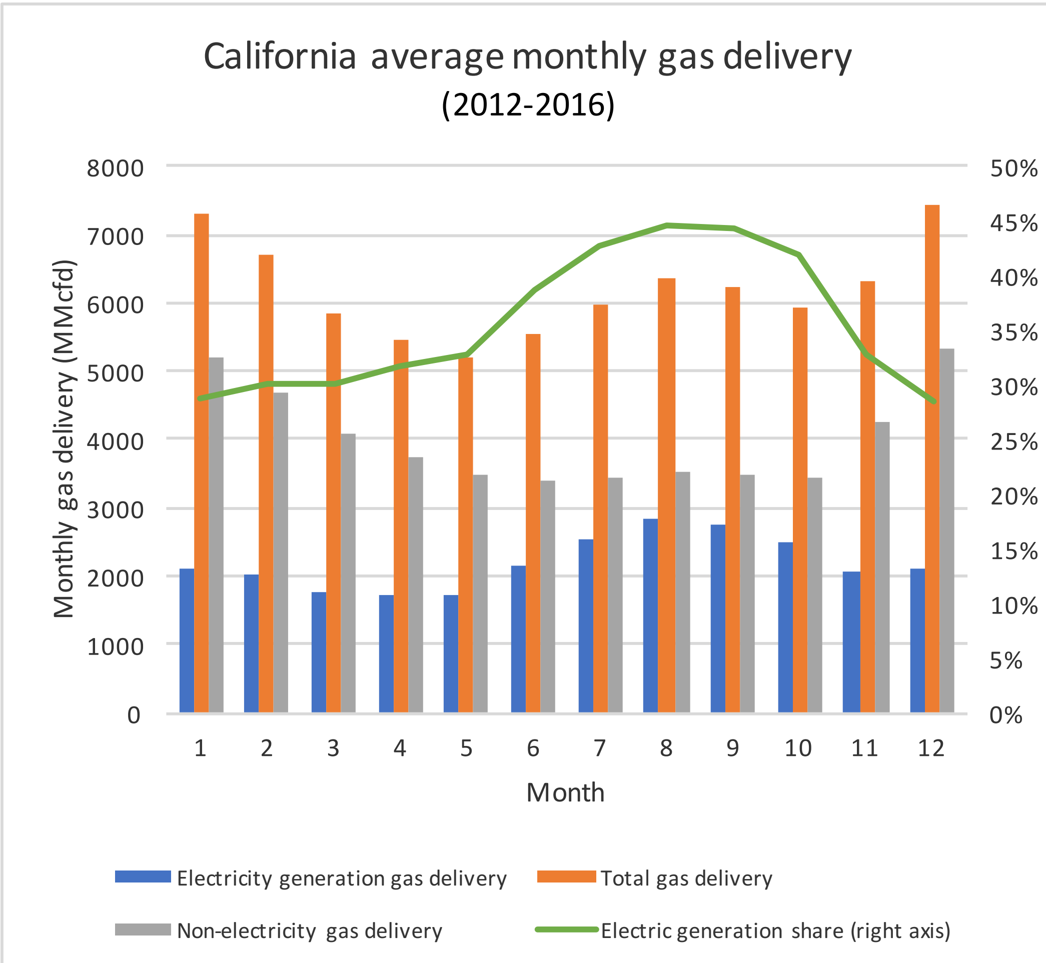


Figure 1. California average monthly gas demand, showing electricity and non-electricity breakdown. Authors' analysis based on data from EIA (2016).

Conclusion 3.5: Although we do not know what the decrease in peak natural gas demand might be, the average reduction in gas use of 600-1,200 MMcfd would not be enough to eliminate pipeline capacity deficits that are currently as much as 4,300 MMcfd.

3.2.2. Gas Demand for Electricity Generation

By comparison, we found that electricity demand for natural gas remains about the same in 2030 as today, but renewable electricity generation share increases in all scenarios, consistent with California's current policy (SB 350) goal of achieving 50% renewable electricity generation in 2030. According to E3 (2015a), the share of renewable generation increases from 27% in 2015 to ~40-50% in 2030, depending on the scenario, while the amount of natural gas used for electricity generation remains about the same or (for one scenario) increases by 14%. Electricity demand is, however, projected to increase by 8 to 14%, resulting in a change in the use of natural gas per kWh generated of between a 14% decrease and a 6% increase. UGS can act as a physical (and financial) hedge against the uncertainty in the amount of renewable generation and electricity demand that actually materializes in 2030.

Finding: The highest gas use for electricity generation occurs during summer months, roughly July-October (Figure 1). The highest output for both wind and solar also occurs in summer months, peaking in June in both cases (Figure 2). For wind, output declines steadily toward a winter low in December-January, whereas for solar, output remains high through September, after which shorter days and more cloud cover diminish statewide output toward a winter low. Gas use for electricity generation is expected to decline much more in summer than in winter by 2030.

Conclusion 3.6: If California continues to develop renewable power using the same resources the State employs today, these will be at a minimum in the winter, which could create a large demand for gas in the electric sector at the same time that gas demand for heat peaks. Consequently, the winter peak problem that exists today may remain or possibly become more acute, making UGS even more important unless California deploys complementary strategies including energy storage, demand response, flexible loads, time-of-use rates, EV charging, and an expanded or coordinated western grid.

While the contribution of wind, solar, and other renewables to electricity generation in 2030 remains uncertain, E3's projections suggest somewhat more solar output than wind, indicating less reliance on natural gas as wind output falls in late summer (E3, 2015a; CPUC, 2017).

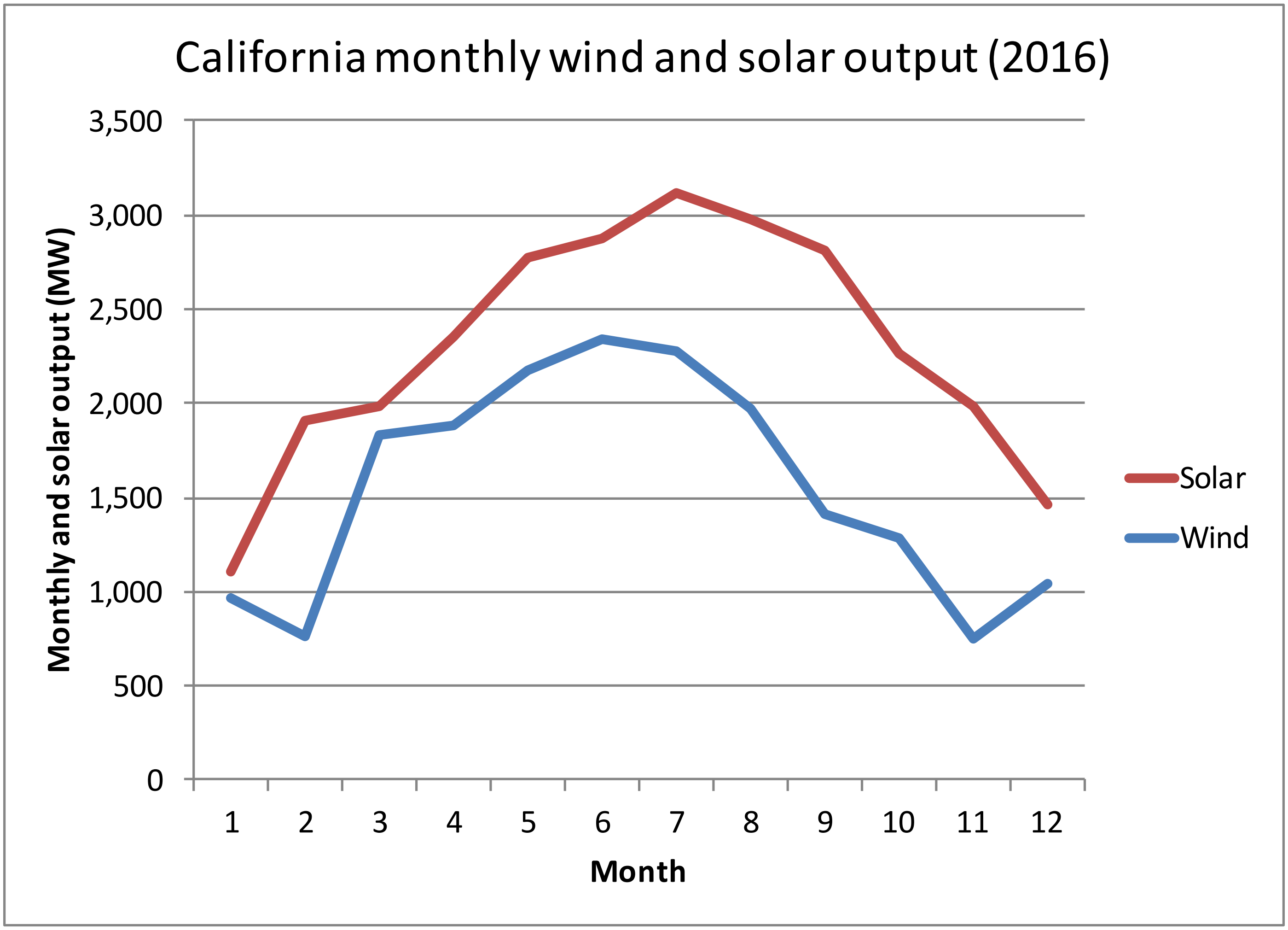


Figure 2. California monthly average wind and solar output in 2016. Reproduced from data in CAISO (2017a, Figure 1.8).

Note that whereas solar energy obviously peaks during the day, wind output in California peaks at night in summer, somewhat making up for the fall in solar output during the waning hours of the afternoon. See Figure 3.

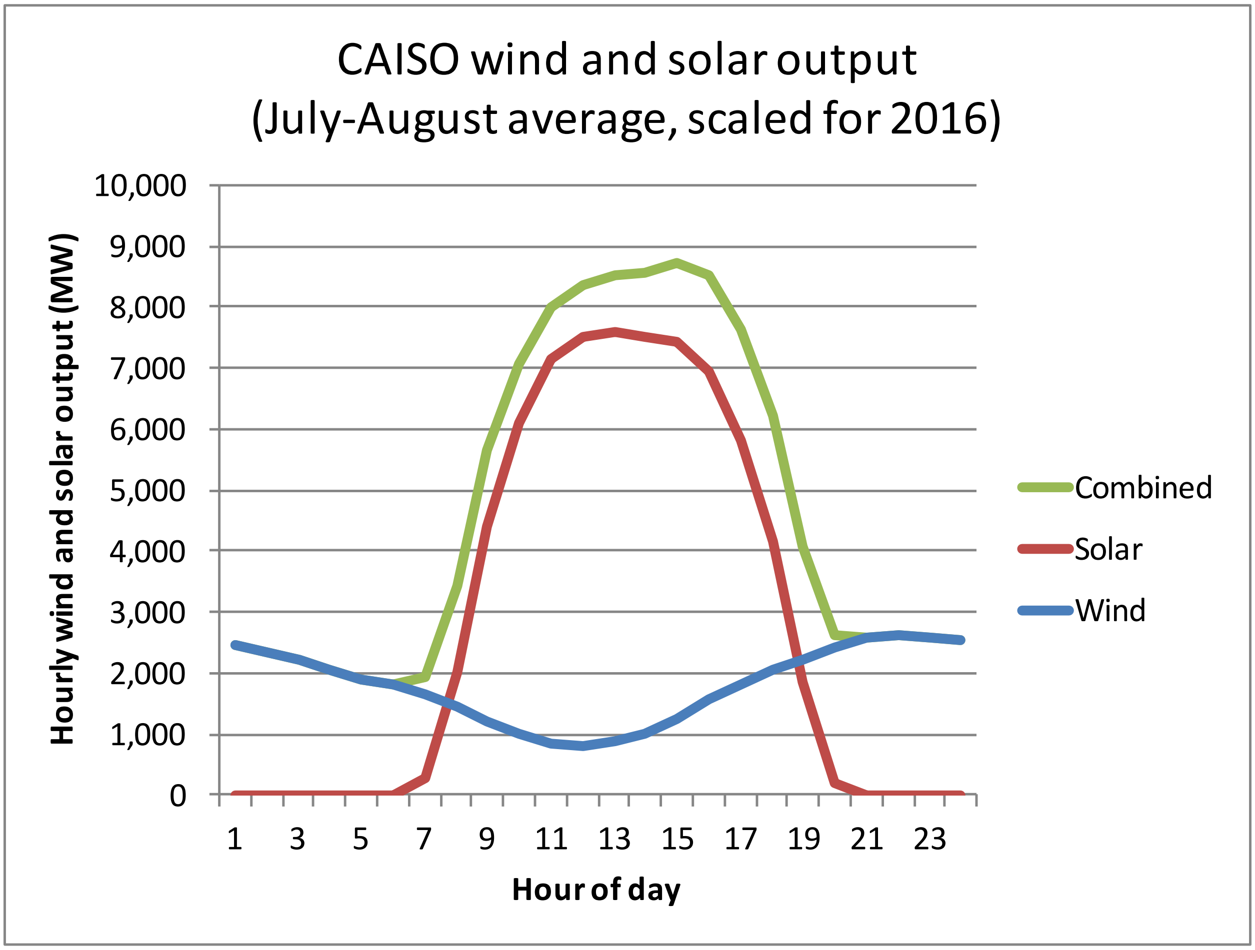


Figure 3. California average wind and solar output by hour for July-August, based on 2014 data (CAISO, 2014c) scaled approximately by 2016 solar capacity.

3.2.3. Hourly Gas Demand

The CEC developed scenarios of hourly gas demand for electricity generation from 2017 to 2030 that complies with all California policies through 2030, including a doubling of additional achievable energy efficiency, increased renewable generation, increased energy storage, and increasing numbers of electric vehicles, among other policies (A. Tanghetti, pers. commun., 2017). Projections shown in Figure 4 are simulations from the CEC "2xAAEE" case, which best represents future policy. The data represent 1-in-2 year daily gas demand for electricity generation for the State. One can observe a general decrease in natural gas use in all seasons, with the largest decreases between April and November. Whereas in 2017, natural gas use encounters a brief minimum in March, by 2030 this low period extends for three full months, from April through June. Natural gas use increases significantly in July in both 2017 and 2030, owing to the onset of higher summer temperatures.

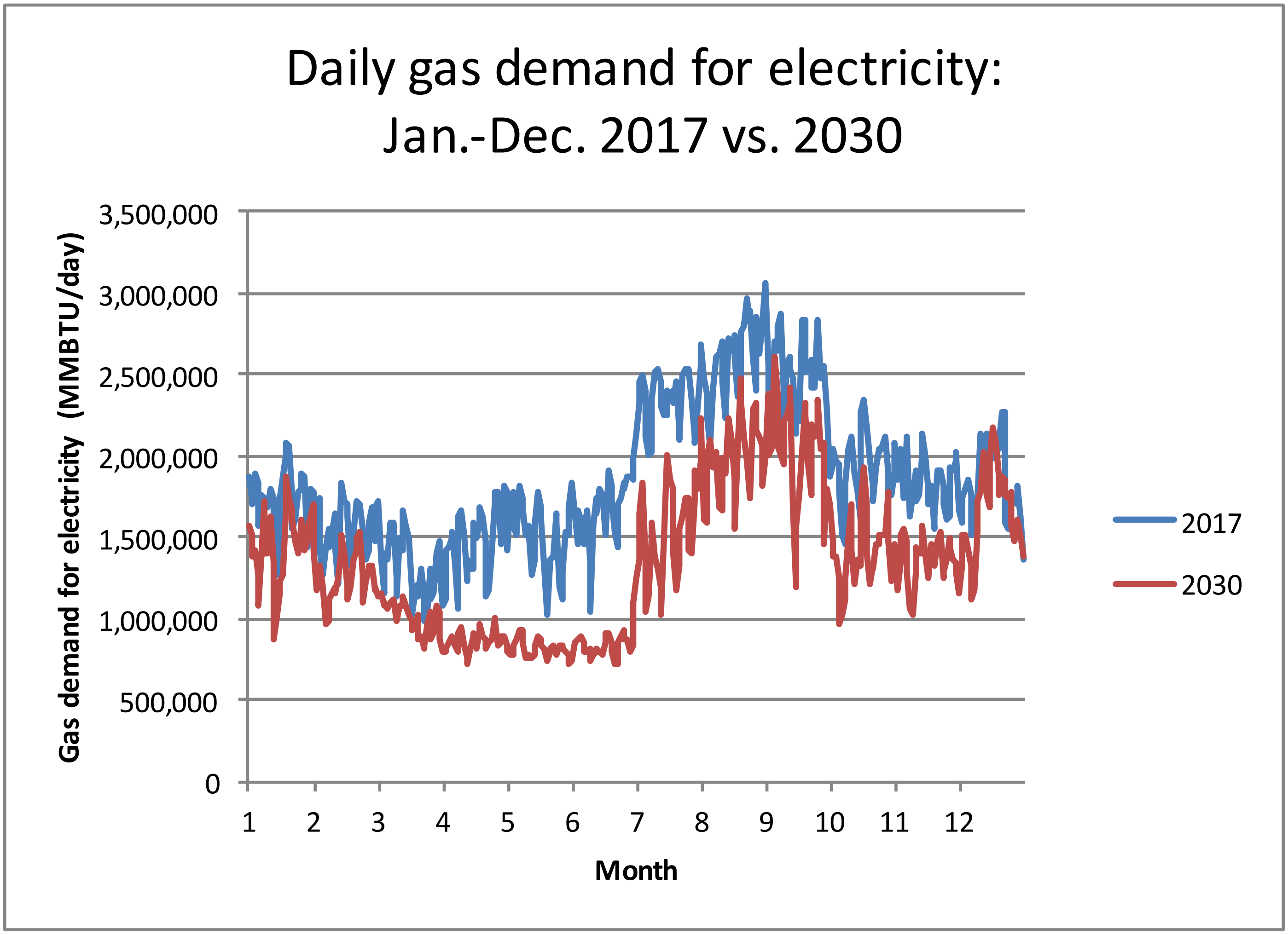


Figure 4. CEC projected 1-in-2 year daily average natural gas demand for electricity generation in California in 2017 and 2030. Projections follow the CEC "2xAAEE" scenario assumption, which is consistent with current and future policies.

Figure 4 does not, however, provide any insight into the hourly changes in natural gas demand. Monthly averages by hour in 2030 are shown for selected months in Figure 5, demonstrating the range of gas use over the year. Peak gas use as well as minimum-to-maximum gas ramps occur in September, whereas lowest gas use occurs in June. Minimum gas use occurs in the middle of the day when solar output is at a maximum (even in winter), with maximum use generally occurring in early evening (particularly in late summer). When daily gas use is high, steep ramps in natural gas use occur in early morning (~8 a.m.) when solar output is growing, and afternoon (~4 p.m.) when solar output falls off and electricity demand is growing.

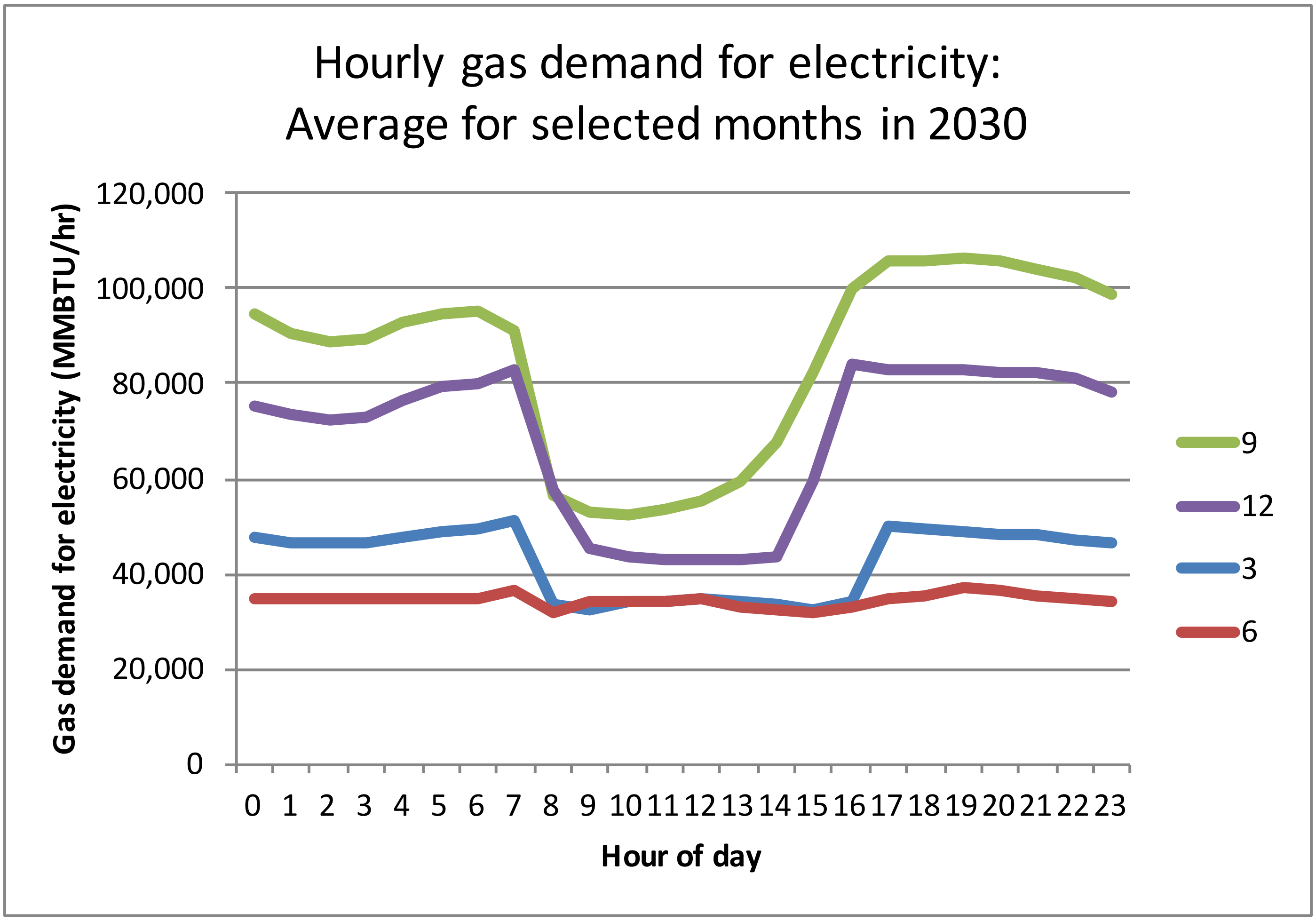


Figure 5. CEC projected diurnal 1-in-2 year average monthly natural gas demand for electricity generation in California in 2030 for selected months. Projections follow the CEC "2xAAEE" scenario assumption, which is consistent with current and future policies.

Comparing these hourly gas use profiles in 2030 to 2017 shows significant differences. Two months are shown that span the observed range in gas use for 2030: June and September. See Figure 6. For September, when electricity demand is highest because of air conditioning use, there is a large reduction in midday gas use as solar provides significant capacity during those hours, as well as reductions in early morning and evening hours, due to increased energy efficiency measures. Daily ramps are also much deeper: the average daily difference in gas use between 8 a.m. and 8 p.m. increases from 25,000 MMBTU/hr (~580 MMcfd) in 2017 to 54,000 MMBTU/hr (~1,250 MMcfd) in 2030. For June, when electricity demand is lower, gas use is more uniformly lower across the day, with a ~50% average decrease between 2017 and 2030, but peak use in morning and evening hours are also noticeably reduced. For other months (not shown), significant decreases in gas use occur during sunlit hours, along with more modest reductions in other hours.

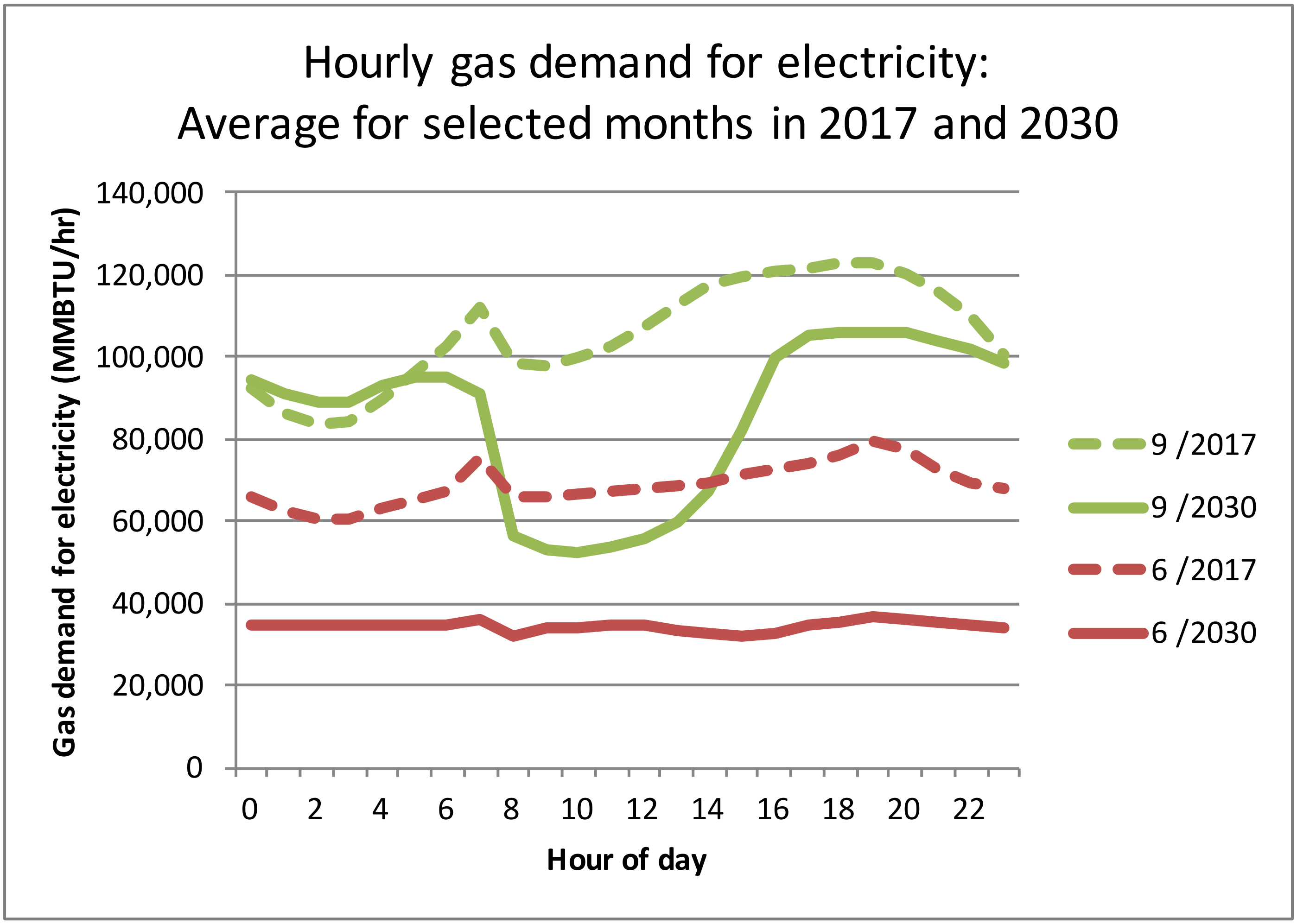


Figure 6. CEC projected diurnal 1-in-2 year average monthly natural gas demand for electricity generation in California in 2017 vs. 2030 for June and September.

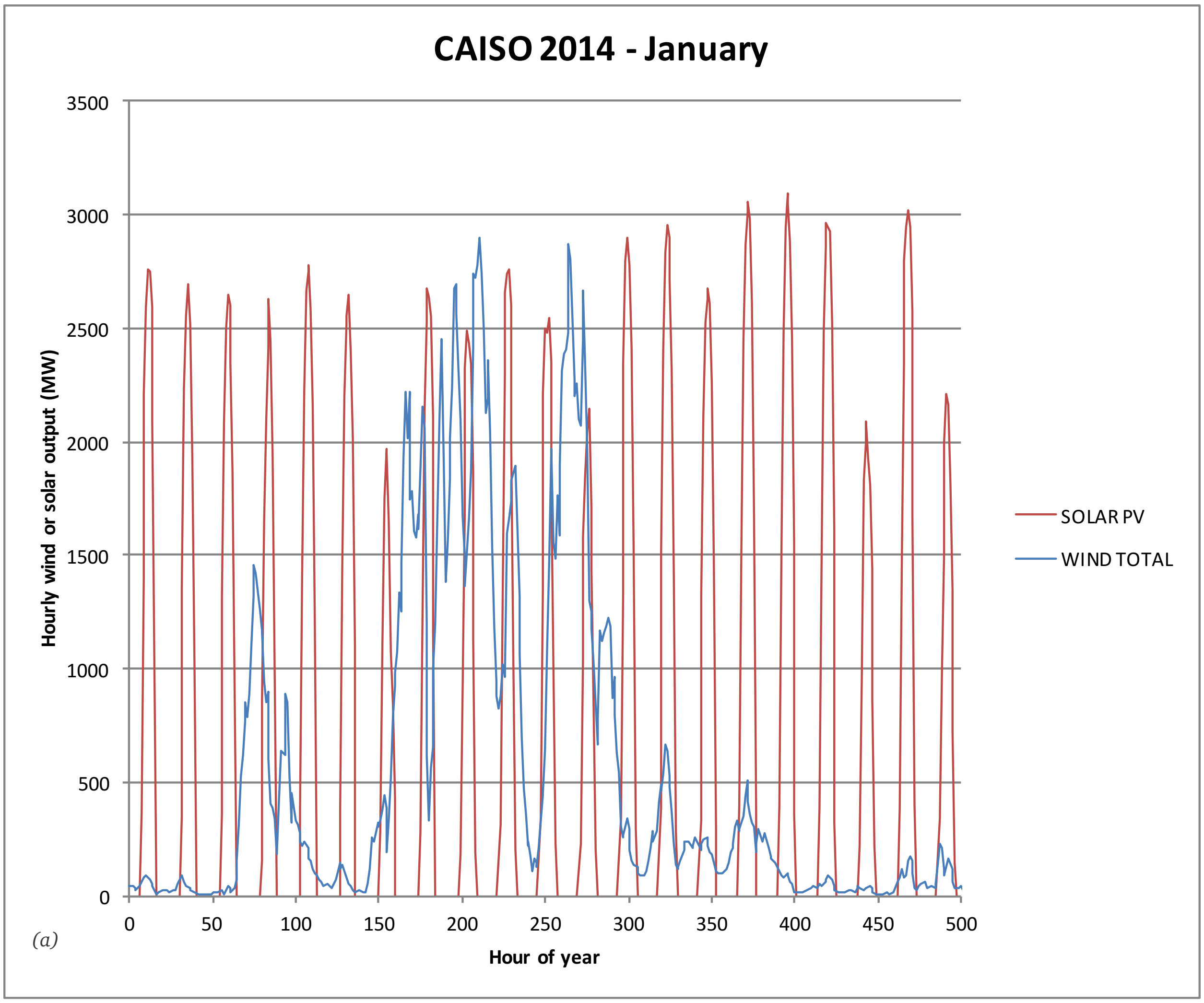
While only summer months are shown in Figure 6, winter months show behavior intermediate between that of June and September.

Finding: Based on State policies, CEC projections indicate that overall demand for natural gas will decrease in both summer and winter, allowing for increased flexibility for natural gas injection into storage. However, CEC projects that daily natural gas ramping capability requirements will increase in most months (July through March).

Conclusion 3.7: By 2030, an increase in the need to use gas to supply ramping capability could result in placing greater reliance on UGS.

3.2.4. Gas Needed to Back Up Intermittent Renewables

With the expected increases in both wind and solar generation, there is also increased intermittency in generation, with wind displaying large swings in output over multiple hours to days, and solar displaying a pronounced diurnal cycle with occasional drops in daytime output due to weather events. See Figure 7, which shows a snapshot of statewide hourly output during 21 days in January and June 2014. Figure 8 shows the same data but with wind and solar output combined to show total intermittent renewable output. June represents one of the highest wind and solar output periods of the year.



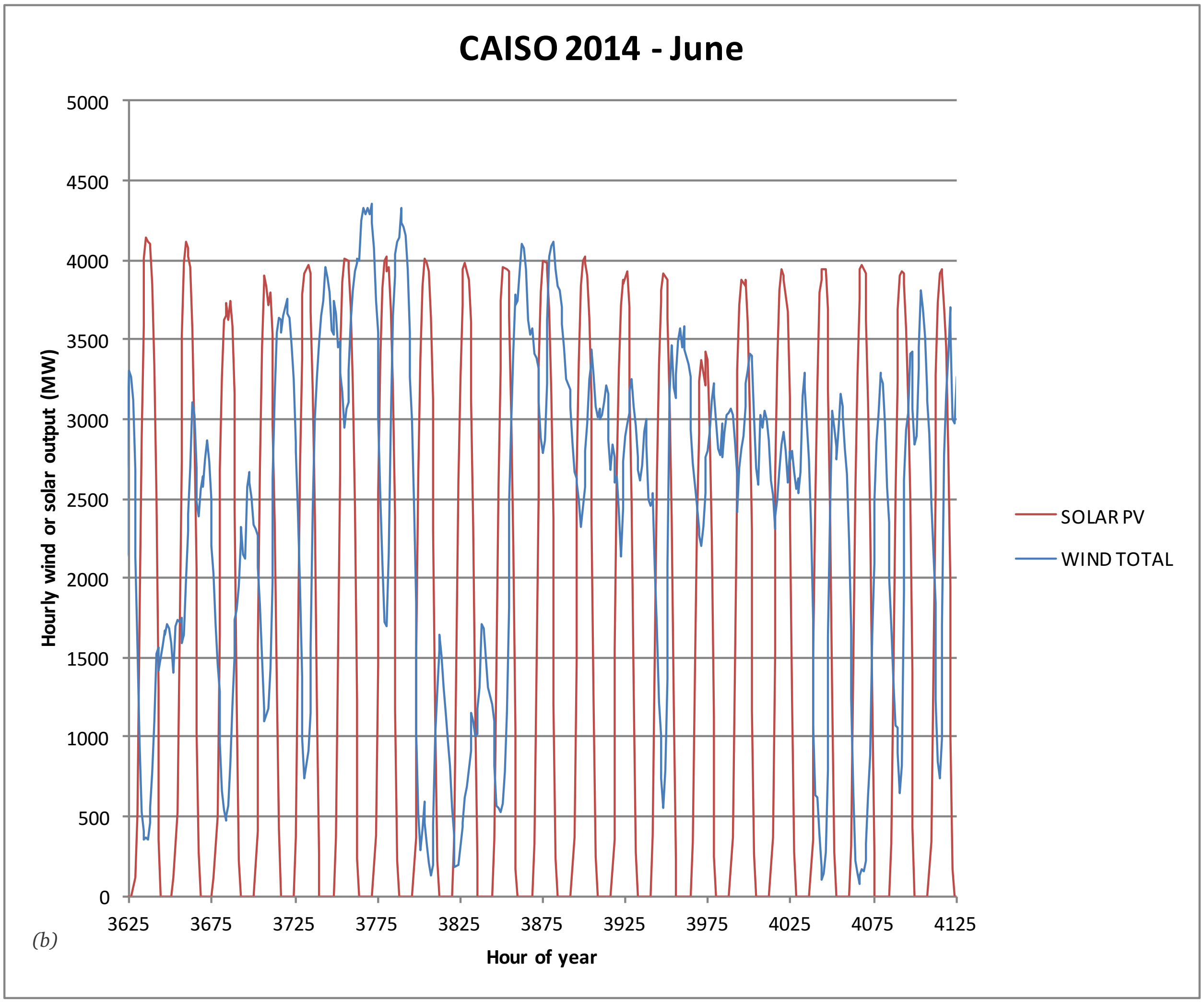
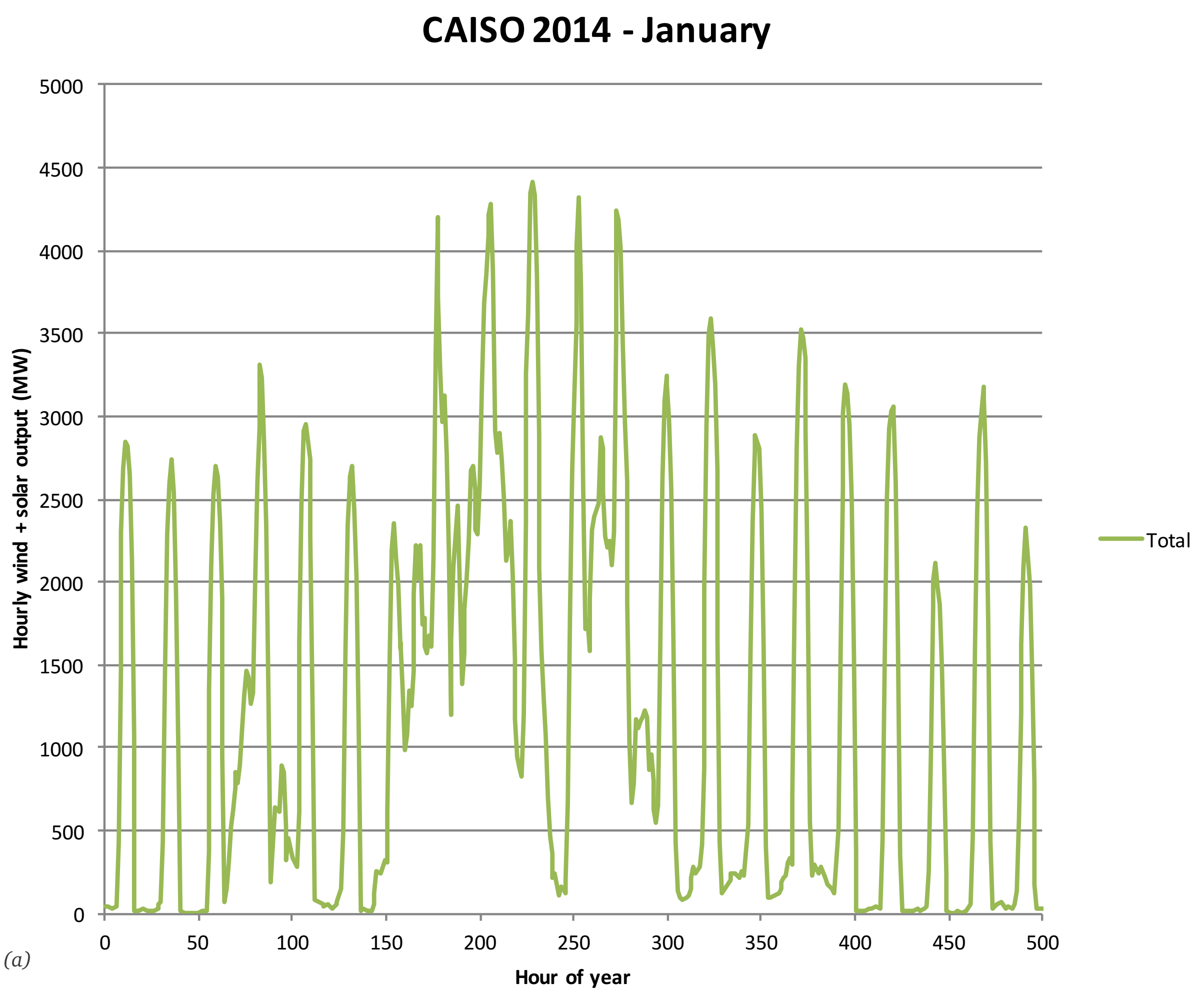


Figure 7. CAISO 2014 (a) January and (b) June wind and solar hourly output. Authors' analysis based on data from CAISO (2014c).


CAISO 2014 - January
Hourly wind + solar output (MW)
5000
4500
4000
3500
3000
2500
2000
1500
1000
500
0
0
50
100
150
200
250
300
350
400
450
500
Hour of year
Total

(a)

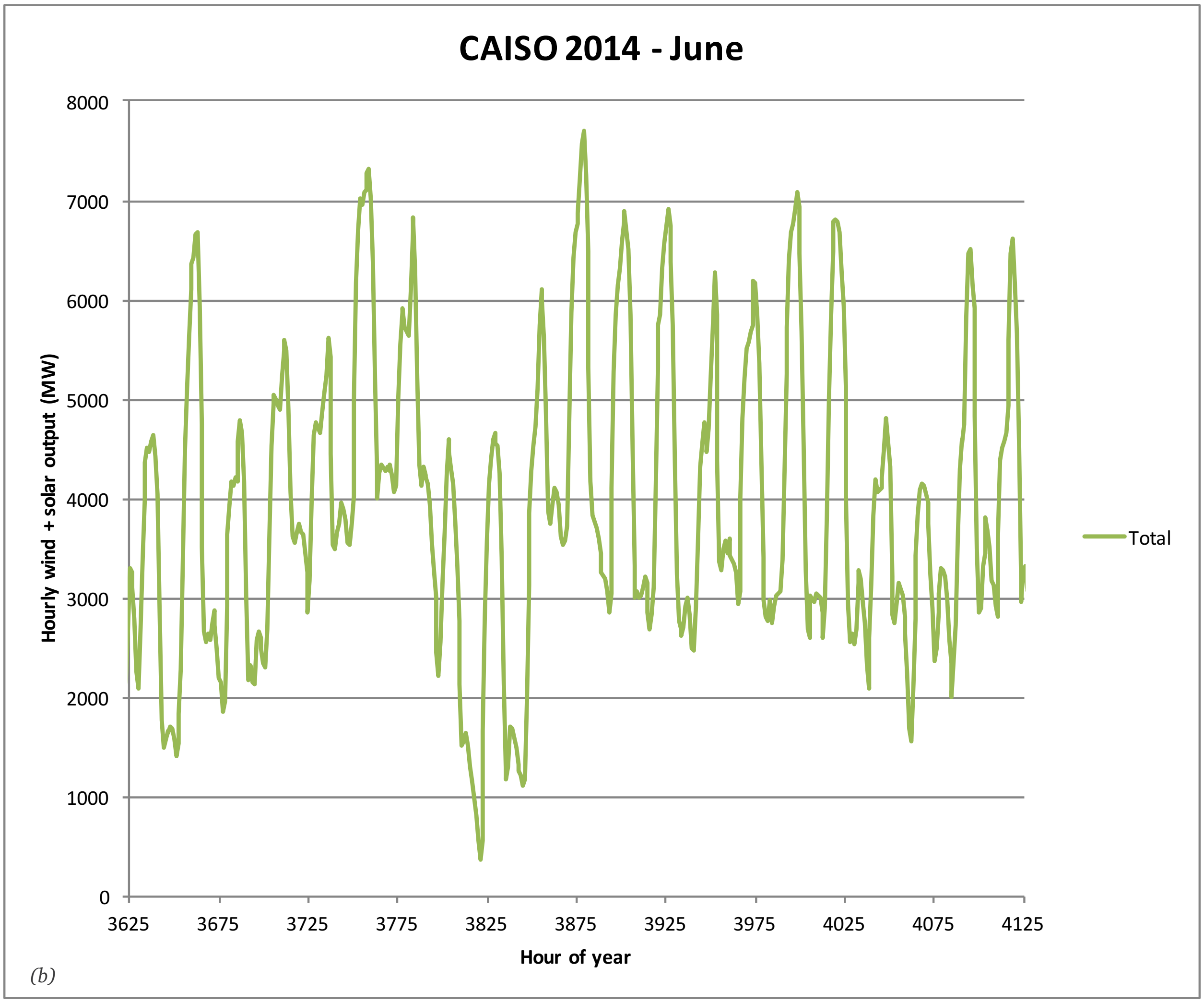


Figure 8. Same data as shown in Figure 7 but with wind and solar output combined for (a) January and (b) June 2014.

Finding: January regularly has periods when the combined output of solar and wind is nearly zero, particularly at night when solar is not operating and the wind dies down. In June, average outputs for solar and wind are much higher than January, and a strong anticorrelation between wind and solar keeps the combined output significantly higher than zero in most hours. However, there are still periods where wind output falls to almost zero, sometimes for multiple days at a time, causing dramatic (and sometimes very rapid) drops in total output. In Germany, periods of low solar and wind output are labeled "*dunkelflaute*", which literally translates as "dark doldrums" (Morris, 2016). This variability must be mitigated to ensure reliable electricity. Today the load is balanced mostly with a combination of natural gas turbine generation and hydropower.

In the future, energy storage, flexible loads, and imported (or exported) electricity could play a role in firming intermittent renewable energy. The more that other options can be used to balance variability in electricity generation, the lower the need will be for gas generation, and the lower the need to withdraw gas from storage to resolve gas imbalances caused by renewable generation.

Finding: Wind generation capacity (at ~4.9 GW) has not increased since 2014 and is expected to remain constant through 2018. Utility-scale solar PV is expected to more than double, from 4.5 GW in 2014 to 9.1 GW in 2018 (CAISO, 2015, 2016b, 2017b). The contribution from wind variability will be similar to that shown in Figure 7 and Figure 8 over the next few years, but as solar generation is always zero in the night, the solar variability will continue to grow, exacerbating the total intermittency variation.

Finding: To mitigate expected generation variability, the California Independent System Operator (CAISO) has estimated that almost as much flexible generation capacity as intermittent renewable generation capacity will be needed: for 2018, it estimates that ~16 GW will be needed to balance ~18 GW of intermittent renewables (with this capacity adding some additional intermittent renewables including a portion of behind-the-meter PV generation to the wind and solar capacities mentioned above) (CAISO, 2017b). This flexible generation capacity varies monthly, with a minimum near ~11 GW in July and a maximum in December. See Figure 9.

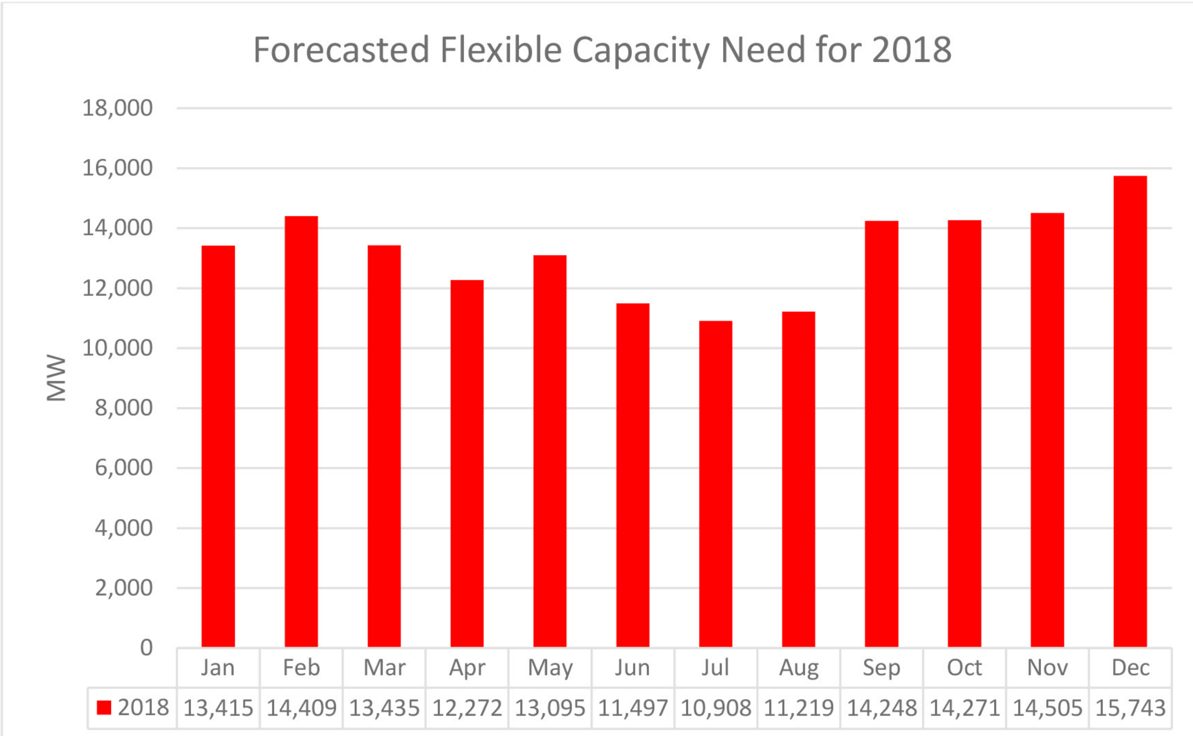


Figure 9. Forecasted flexible generation needed to balance CAISO intermittent renewables in 2018. Reproduced from Fig. 2 in CAISO (2017b). Licensed with permission from the California ISO.

The need to back up intermittent resources includes concerns about how fast the backup energy might have to be supplied, i.e., the ramping requirements. A timely example of the amount of flexible capacity needed to back up the increasing amounts of solar PV is how CAISO responded to a three-hour solar eclipse event on the morning of August 21, 2017. With ~18 GW of solar generating capacity (at both utility- and rooftop-scale) on California's grid, about 3.4 GW was estimated to be lost at the peak of the eclipse at 10:22 am (Fairley, 2017). Hydropower, gas-fired generation and regional electricity transfers were all possible options for filling the gap (CEC, 2017), but the ramping rate was very steep, up to 100 MW/min., or more than three times the normal ramp rate at that time of day (Fordney, 2017). This rate is close to the historical evening peak ramp of 13 GW over two hours (~110 MW/min.). Similarly, a 2015 total eclipse centered in Europe impacted 90 GW of solar capacity, and was considered "a true stress test" for the electricity grid, though it was handled without incident (Walton, 2017). In both cases, gas generation was a key part of the solution.

For 2030, in order to reach the 50% renewable generation targets, renewable generation will have to more than double from current levels. While the portion of generation coming from intermittent wind and solar are not knowable in advance, most studies suggest that the vast majority of it will come from these sources (e.g., E3, 2015a; Brinkman et al., 2016; Casey et al., 2016). Some of this intermittent capacity could also be imported from neighboring states.

Finding: Brinkman et al. (2016) explored a model of California's electricity system in 2030 under a 50% GHG reduction scenario, which assumed 56% renewable electricity generation that included 6% customer-sited solar PV. The study found that up to 30 GW of gas generation would be needed to backup these renewables, though half of this capacity would be utilized less than ~25% of the time, making capital investments to insure the availability of such gas generation difficult. See Figure 10.

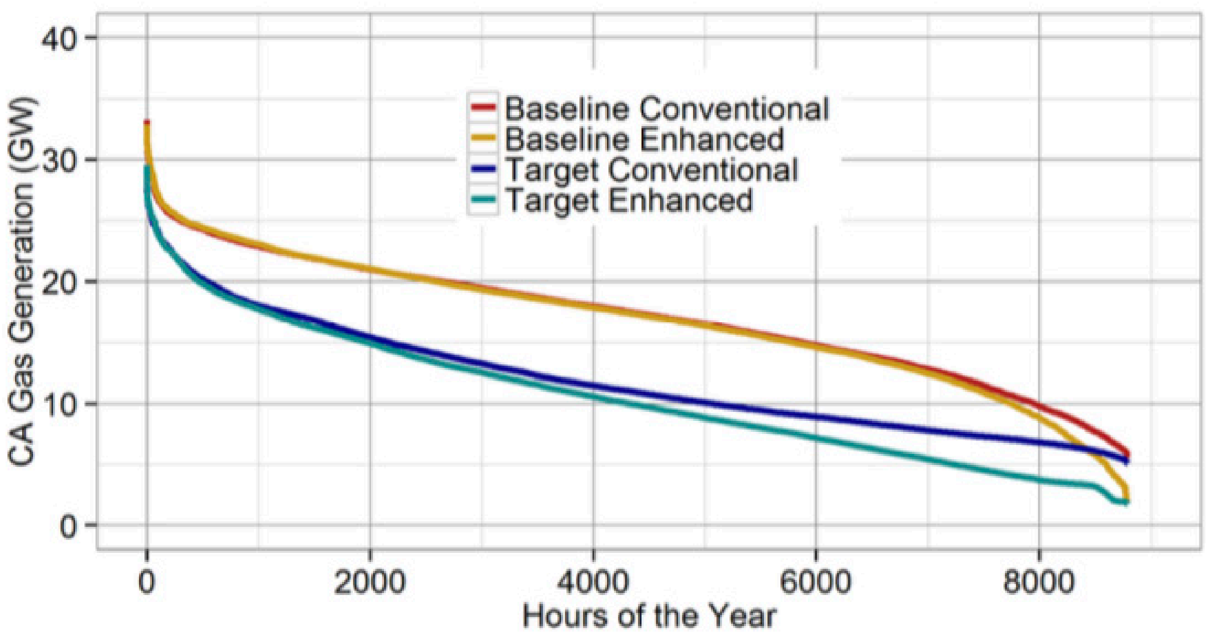


Figure 10. Duration curve of California gas generation for 2030. "Baseline" refers to a non-compliant scenario with 36% renewable generation including customer-sited solar PV. "Target" refers to a 2030-compliant scenario with 56% renewable generation including customer-sited solar PV. "Conventional" refers to a level of grid flexibility similar to today, whereas "Enhanced" provides additional import/export flexibility, grid-scale energy storage and relaxed limits on hydro and PHES capacity to provide ancillary services. Reproduced from Fig. 8 in Brinkman et al. (2016). (Note that both the Baseline and Target scenarios converge to the same gas generation capacities at 8,760 hours, reflecting baseload conditions driven by the amount of supply flexibility assumed in the model rather than the amount of renewable capacity.)

E3 (2015) also modeled several 2030 scenarios assuming 50% renewable electricity generation (a total of 53 GW of intermittent generation capacity, with 61% coming from solar resources). They found that 34 GW of dispatchable gas generation would be needed, along with ~30 GW of other flexible generation capacity to balance the electricity system. Thus, the total flexible resource capacity exceeds the intermittent renewable capacity, but some of these resources are used to mitigate other variability on the grid, such as changes in load. Broadly speaking, this result is similar to what CAISO found in its assessment of needed flexible generation capacity in 2018 (CAISO, 2017b). European studies (ENTSO-E, 2015; Verdolini et al., 2016) also found that roughly equal amounts of dispatchable fossil backup capacity were required for any additions in renewable generation in the long term, in order to handle *dunkleflaute* conditions. For instance, for 2025, ENTSO-E projected that at 7 pm, ~235-250 GW of 255 GW of wind capacity and ~110-140 GW of ~140 GW of solar capacity might be unavailable at different times of year; see Figure 11.

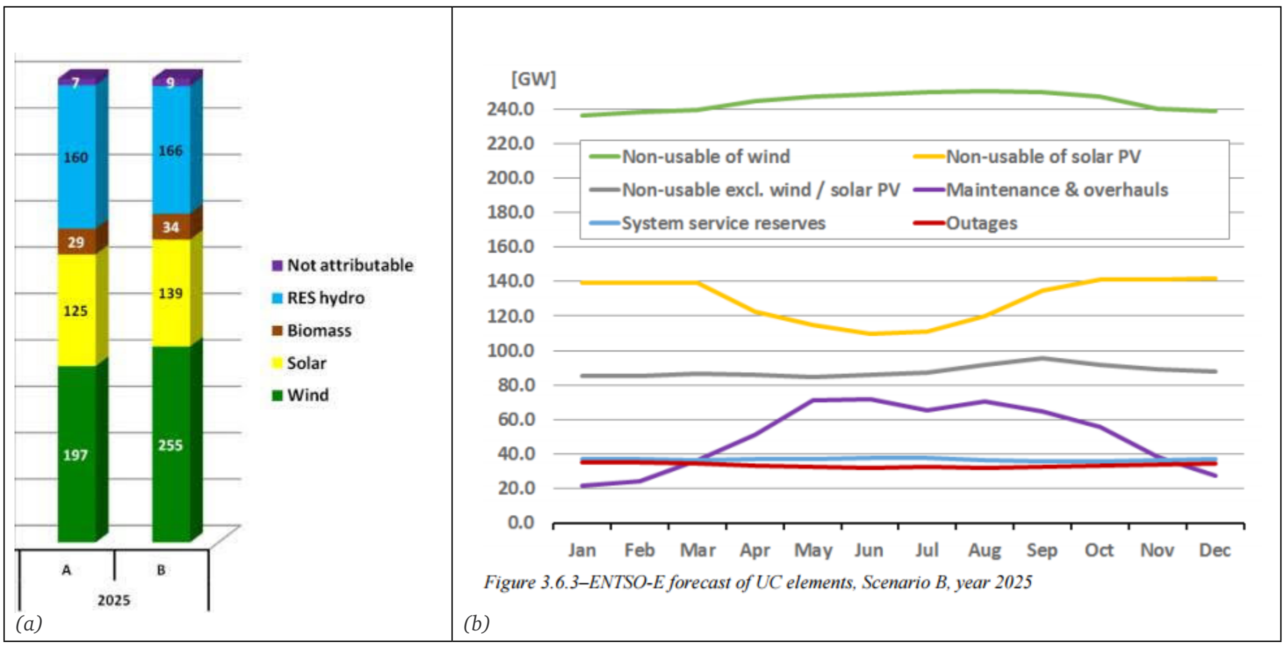


Figure 11. Western European electricity generation capacities at 7 pm in 2025: (a) available renewable capacity in January (B corresponds to a "Best Estimate" scenario), and (b) unavailable capacity across the year. Data reproduced from Figures 3.5.2 and 3.6.3, respectively, in ENTSO-E (2015).

During periods of high intermittent renewable output, renewable resources may occasionally need to be curtailed to maintain system reliability (CAISO, 2017c).[3] Such curtailment currently represents a very small fraction of total renewable generation (~0.2%), but in the first three months of 2017, it averaged 3% of total wind plus solar generation, and on March 11, 2017, more than 30% of solar output was curtailed in one hour.

As the renewable fraction on California's grid grows, curtailments may need to increase unless California deploys complementary strategies including energy storage, demand response/flexible loads, time-of-use rates, EV charging, and an expanded and/or coordinated western grid. Although this curtailment does not necessarily impact UGS, increasing the percentage of intermittent renewables will tend to increase curtailment and will help to spur thinking about how to balance load that may affect the need for gas, positively or negatively.

California has a huge, flexible natural gas fleet that exists already; adding renewables off-loads gas generation that can then be used for balancing and flexibility. However, ramps that the gas system has to meet could create large surges in gas demand for power generation and may drive a need for gas reserve capacity similar to what we have today.

Finding: The ~30 GW of backup natural gas capacity needed in 2030 translates into ~5,000 MMcfd, assuming an average heat rate of ~7,000 Btu/kWh for natural gas turbines (a reasonable assumption based on average heat rates of future California natural gas plants provided from E3, 2015a). The demand for gas to provide backup for renewable energy comes close to current pipeline import capacity of ~7,500 MMcfd
(see Chapter 2),

While statewide investor-owned utility demand response capacity has fallen from ~2,600 MW in 2012 to ~2,000 MW in 2016[4] (mainly due to increased program stringency) (Murtaugh, 2017), its potential has been estimated to provide system-wide fast-response potential capacities totaling 5,600 MW in 2020 and 7,300 MW by 2025 (Alstone et al., 2016). Assuming a linear growth in potential capacity to 9,000 MW in 2030, and converting this capacity into a natural gas flow, results in a potential reduction of ~1,500 MMcfd in 2030 due to demand response, which, while large, is insufficient to reduce the dependence on UGS to mitigate renewable intermittency.

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3. Renewable curtailment is sometimes necessary if the power cannot be immediately utilized, as oversupply can threaten grid stability, especially where there are transmission bottlenecks, imbalances, or voltage or frequency instabilities.

4. Note that of the ~2,000 MW capacity in 2016, ~800 MW were price-responsive resources and ~1200 MW were reliability-based resources priced at between 95% and 100% of the bid cap of $1000/MWh. Also, demand response capacity may be subject to constraints so may have limited availability for day-to-day load balancing.

Conclusion 3.8: Although California's climate policies for 2030 are likely to reduce total gas use in California, they are also likely to require significant ramping in our natural gas generation to maintain reliability. These surges of gas demand for electric generation may require UGS.

3.2.5. Summary of 2030 Scenario Assessment

Finding: Despite an overall expected decrease in natural gas use in both summer and winter, the use of natural gas for electricity generation may become "peakier" in order to balance the increasingly intermittent output from wind and solar generation, and this potential peakiness could be nearly as large as today on an hourly or seasonal basis. However, these additional demands on UGS are likely to be small compared with the ~1,000 Bcf that is normally injected into and withdrawn from storage every year (see Figure 9 in Chapter 2).

Conclusion 3.9: The total amount of UGS needed is unlikely to change by 2030.

Recommendation 3.2: California should develop a plan for maintaining electricity reliability in the face of more variable electricity generation in the future. The plan should be consistent with both its *goals* policies and its *means* policies, notably for 2030 portfolio requirements and beyond, and should account for energy reliability requirements on all time scales. This plan can be used to estimate future gas and UGS needs.

3.3. DEMAND FOR UGS IN 2050

The ambitious GHG targets of an 80% reduction below the 1990 level by 2050 will require much more dramatic changes to California's energy system than were found for 2030. This was consistently displayed across the 23 California, 29 U.S. and two global GHG-compliant scenarios that we examined for 2050. However, the types of changes were not necessarily all in the same direction, and scenarios tended to cluster into distinct categories. As a first pass, we examined each scenario with respect to its change in total annual demand for natural gas relative to a recent reference year, and found that scenarios either significantly increased their natural gas demands (to ~150% of the current level), remained close to today's level, or significantly decreased them (to ~50% or less of today's level). All scenarios whose natural gas demand significantly increased made heavy use of CCS technology, allowing for the expansion of natural gas while dramatically reducing its GHG emissions (though many scenarios with lower amounts of CCS technology did not increase overall natural gas demand beyond today's level). Scenarios that strongly relied on low-carbon gas to reduce GHG emissions while continuing to use gaseous fuels in the energy system tended to have natural gas demand levels similar to today. And those scenarios with the lowest demand for natural gas tended to have significant building electrification, and greatly expanded the use of non-fossil electricity generation (either renewables, nuclear, or both), though these elements were also present in scenarios with higher natural gas demand levels. Some scenarios also greatly expanded their use of hydrogen. (The amount of hydrogen used was not included in our total gas demand metric.)

As discussed in Chapter 2, it is largely peak demand for gas that drives the need for UGS, as California pipeline importation capacity is insufficient to meet demand in all hours of the year. As the demands for—and uses of—gas change, it may be possible to decrease reliance on UGS, but on the other hand, it may be necessary to increase the capacity to handle greater reliance on gas in certain periods. To determine how changes in the 2050 energy system might affect peak demand for gas requires detailed information of the many factors that affect that demand on multiple time scales. Table 3 lists these elements and their expected effects on gas and UGS demand.

Table 3. Elements of a 2050 electricity system that could affect gas and UGS demand.

Element	**Total gas demand effect**		**UGS effect (driven by peak demand)**		**Comments**
	Winter	**Summer**	**Winter**	**Summer**	
Electricity sector					
Increased annual electricity demand	Increase		Neutral or increase[a]		
Increased building electrification	Increase		Neutral or increase[a]	Neutral	Heat pumps are less efficient in cold weather
Increased vehicle electrification	Unclear[c]		Unclear[c]		Transport demand is roughly flat seasonally
Increased fossil-CCS generation	Increase		Increase		Also increase in CO2 transport and storage
Increased intermittent renewables	Decrease		Unclear		Renewables may decrease natural gas use overall but will increase backup requirements, particularly in winter when renewable output is lowest
Increased flexible, non-fossil generation	Decrease		Neutral or decrease[a]		Flexible generation will have a smaller effect on backup requirements
Increased energy storage, flexible loads, regional coordination, etc.	Decrease		Neutral		These approaches cannot reduce reliance on UGS for multiple-day and seasonal mismatches

a Depending on how much peak demand is affected

b Assuming hydrogen is not produced locally (from electricity or biomass) and thus requires pipeline and storage infrastructure

c Vehicle electrification increase electricity demand, but flexible charging could lower ramping requirements

Element	Total gas demand effect		UGS effect (driven by peak demand)		Comments
	Winter	Summer	Winter	Summer	
Increased power-to-gas	Decrease		Neutral or increase[a]		Produced hydrogen or methane must be stored
Increased pure hydrogen production	Increase (if generated from electricity) or neutral		Neutral or increase[a]		
Increased wildfires causing electric transmission outages	Neutral	Neutral or increase	Neutral	Neutral or increase[a]	Primarily occurs in summer
Increased climate change effects	Neutral	Increase	Neutral	Neutral or increase[a]	Primarily affects summer generation
Non-electricity sector					
Increased annual natural gas demand	Increase		Neutral or increase[a]		
Increased building electrification	Decrease		Neutral or decrease[a]		Shift of gas demand to electricity sector
Increased low-carbon gas (in pipeline supply)	Neutral		Neutral		SNG or hydrogen use may require CO2 transport and storage
Increased pure hydrogen	Neutral for natural gas; increase in total gas demand		Neutral for UGS; increase in pure hydrogen storage[b]		Depending on hydrogen production method, may also require CO2 transport and storage
Increased natural gas vehicles	Increase		Neutral or increase[a]		Transport demand is roughly flat seasonally
Increased climate change effects	Decrease	Neutral	Neutral or decrease[a]	Neutral	Primarily affects winter gas demand

a Depending on how much peak demand is affected

b Assuming hydrogen is not produced locally (from electricity or biomass) and thus requires pipeline and storage infrastructure

c Vehicle electrification increase electricity demand, but flexible charging could lower ramping requirements

3.3.1. Scenarios for 2050

In all scenarios, sufficient quantitative details of the energy system to make a robust assessment were lacking, so we relied heavily on a handful of scenarios from E3 (2015a) that had the most data available. From these data, plus our own expert judgment, we developed four representative scenarios that provided distinct combinations of energy technology elements that can achieve an 80% GHG reduction goal. Each has very different implications for natural gas demand and UGS. To simplify discussion, we invoke a logic diagram, shown in Figure 12, to illustrate how each scenario is classified, based on three basic parameters: amount of intermittent electricity generation, type of flexible generation, and amount of low-carbon gas:

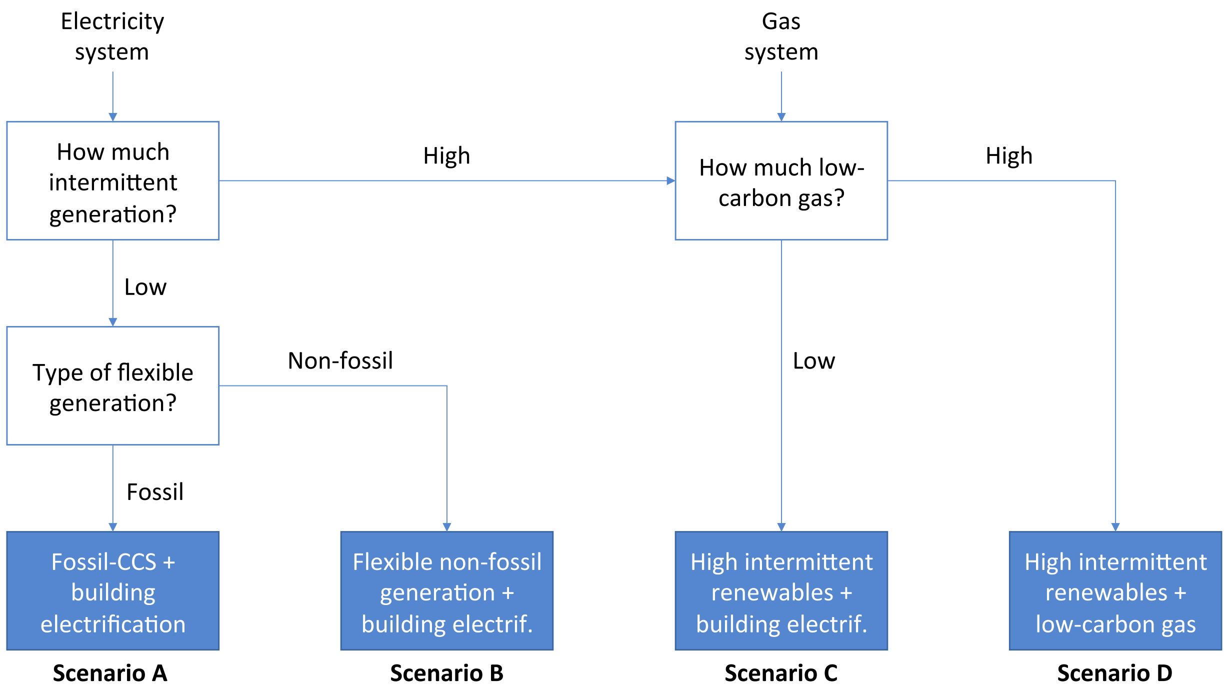

Figure 12. Logic diagram for 2050 scenario classification

Table 4 provides a qualitative summary of the main drivers of change in the four scenarios, along with example scenarios from the literature.

Table 4. Scenario table indicating main drivers of changes and example scenarios.

Scenario	**Main drivers of change**	**Example scenarios**
A: Fossil-CCS + building electrification	Increased share of electricity provided by gas, higher overall electricity demand, larger short-term peaks due to cold weather events (in winter), larger need for renewable backup	Williams et al. (2012) "High CCS," Williams et al. (2014) "High CCS," Wei et al. (2013a) "Inexpensive CCS," Yang et al. (2014) "GHG-S-CCS," E3 (2015a) "CCS," Cole et al. (2016) "Low CCS Cost + low-C target," Risky Business Project (2016) "High CCS."
B: Flexible, non-fossil generation + building electrification	Decreased share of electricity provided by gas, moderating increased use of electricity, smaller need for renewable backup	Williams et al. (2012) "High nuclear," Wei et al. (2013a) "Inexpensive NUC," Nelson et al. (2013) "New Nuclear," Williams et al. (2014) "High nuclear," Yang et al. (2014) "GHG-S-NUC," Yang et al. (2015) "GHG-S-NucCCS," Cole et al. (2016) "Low Nuclear Cost + low-C target," Risky Business Project (2016) "High Nuclear," OECD/IEA (2015) "450 Scenario"[a]
C: Intermittent renewables + building electrification	Decreased share of electricity provided by gas, higher overall electricity demand, larger need for renewable backup	Williams et al. (2012) "High RE," Logan et al. (2013) "CES," Williams et al. (2014) "High RE," several scenarios in Yang et al. (2014) including e.g., "GHG-S-HiRen," E3 (2015a) "Straight Line," Risky Business Project (2016) "Mixed" and "High Renewables" scenarios
D: Intermittent renewables + low-carbon gas	Decreased share of electricity provided by gas, larger short-term peaks due to cold weather events (in winter), larger need for renewable backup	Williams et al. (2014) "Mixed" and "High Renewables," E3 (2015a) "Low Carbon Gas," Risky Business Project (2016) "High Renewables," Yeh et al. (2016)[b]

a Note that the OECD/IEA scenario is one example of a mixed approach combining nuclear, hydro and biomass electricity generation with CCS (as well as some fossil generation with CCS). The White House (2016) "Benchmark" scenario is another example, not included in the above list, that is agnostic over whether the electricity generation not provided by natural gas (<10%) or fossil with CCS (~20%) comes from intermittent renewables, nuclear or biomass with CCS.

b Yeh et al. (2016) reviewed several California GHG-compliant scenarios developed by others, and concluded that biomethane could replace 50% of fossil natural gas in buildings and industry, though greater transport electrification would also be required to meet GHG targets.

These four scenarios are discussed in detail below, but in summary, in addition to increases in energy efficiency, renewable electricity, energy storage, and vehicle electrification:

- Scenario A provides >50% of electricity demand from fossil natural gas combustion with CCS. In order to reduce fossil fuel combustion in other sectors, aggressive building electrification is also pursued. In addition, pure hydrogen production is produced for some vehicles and possibly non-transport uses.

- Scenario B provides >50% of electricity demand from flexible, non-fossil generation such as nuclear, geothermal, hydropower, biomass or other technologies. As for Scenario A, aggressive building electrification and pure hydrogen production are also pursued.

- Scenario C provides ~80% of electricity demand from renewables, the majority of which are intermittent (solar and wind) sources. As for Scenarios A and B, aggressive building electrification and pure hydrogen production are also pursued.

- Scenario D provides most of electricity demand from intermittent renewables as in Scenario C. Unlike Scenarios A through C, however, there is less of a need for either building electrification or pure hydrogen, because low-carbon natural gas is widely available as a fuel. There is also less emphasis on energy storage because natural gas can be used for backup generation. As a result, the pattern of natural gas use is largely unchanged from today.

Note that, in addition to energy storage, flexible loads, and other non-gas-based load-balancing approaches, the E3 (2015a) study invoked significant amounts of P2G to avoid renewables curtailment. This was not present in most other studies. Table 5 summarizes the key parameter assumptions for the four scenarios. Additional quantitative data from E3 (2015a) representing three of the four scenarios (all but Scenario B) can be found in Appendix 3-4: Selected Data from E3 (2015a).

Table 5. Summary of key assumptions for the four 2050 reference scenarios. Estimates based on E3 (2015a) and authors' own analysis, unless otherwise indicated.

	Electricity					Non-electricity		Annual gas demand (relative to today's total natural gas demand)				
Scenario	Annual electricity demand (relative to today)	Renewable fraction: total wind+solar	Fossil-CCS fraction	Electric vehicles: lightduty heavyduty	Building electrification (relative to today)	NGVs (relative to today)	Low-carbon gas fraction	Electricity	Non-electricity	Overall	Pure hydrogen (relative to today's natural gas demand)[a]	Demand for UGS (relative to today)
Today (2016)	100%	27%	0%	0.3M[b]	1	1	0%	~30%	~70%	100%	0%	N/A
A: Fossil-CCS + building electrification	~160%	~40% ~35%	~50%	10M 0.7M	~15	~1.3	~6%	~120%	~30%	~150%	~20%	Increase
B: Flexible, non-fossil generation + building electrification	~220%	~80% ~40%	~0%	10M 1.0M	~15	~1.3	~10%	~10%	~30%	~40%	~20%	Decrease
C: Intermittent renewables + building electrification	~220%	~80% ~75%	~0%	10M 1.0M	~15	~1.3	~15%	~30%	~30%	~60%	~20%	Unclear
D: Intermittent renewables + low-carbon gas	~205%	~80% ~75%	~0%	33M 1.2M	~1.5	~50	~70%	~25%	~75%	~100%	~0%	Unclear

a Indicates volume of hydrogen that may need to be produced, transported and stored, if not generated on demand locally from electricity or biomass resources.

b Data from Cobb (2017).

By comparison, current California policy through 2030 strongly emphasizes renewable electricity (particularly solar PV, with some wind development) (CPUC, 2017), building and vehicle efficiency, vehicle electrification, and low-carbon transportation fuels. Fossil-CCS is not part of the State's plans, and nuclear power is being phased out. Other flexible, non-fossil generation such as geothermal, small-scale hydropower, and biomass are only present in small amounts. Moreover, while energy storage, demand response and regional electricity coordination are expanding, there is very little building electrification or movement toward producing significant amounts of pure hydrogen, though hydrogen fuel is part of the State's long-term roadmap. While there is some interest in utilizing biomethane, large amounts of low-carbon natural gas are also not being pursued. Therefore, overall, many of the elements explored in the four scenarios above are not part of current State policy, though Scenario C comes closest. It was the goal of this report to explore other technical options available to the State that could meet GHG goals with potentially significant implications for UGS.

3.3.2. Scenario A: Fossil-CCS + Building Electrification

By using natural gas with CCS as a primary means of electricity generation, this scenario would require significant increases in gas use. CCS technology would be used with natural gas combined cycle plants to capture ~90% of emitted CO_2, but reliance on natural gas for electricity generation would increase to ~50% or more of total generation, though intermittent renewables would still contribute a higher fraction of total generation than is seen today; assuming SB 350 is maintained, this fraction would need to be at least 50%. Since CCS cannot be economically applied at the scale of individual buildings or vehicles, its uses would be limited to electricity plants and large industrial facilities. Among these industrial facilities could be production of biofuels, biomethane, SNG, or hydrogen.

Aggressive building electrification would be required to keep overall GHG emissions low. This would shift the use of natural gas from being burned directly for heat to being used to generate electricity for heat, because gas used to produce electricity would use CCS to reduce its GHG emissions. As a result, natural gas would be largely phased out of buildings, but overall natural gas use would not decrease, and could increase significantly. Building electrification would result in far more electricity demand in winter, when demand for gas heating is currently highest. Moreover, electric heat pump technologies produce heat at lower efficiencies when ambient outdoor temperatures are low, requiring larger amounts of electricity to provide the needed heat.

Larger amounts (~50%) of intermittent renewables would require everyday firming, planning for unexpected drop-offs in generation capacity, as well as seasonal fill-in capacity when both wind and solar are lower in winter months—all of which would increase the need for UGS or other backup capacity.

New electric loads from transportation (required to minimize total GHG emissions) would contribute to higher overall electric loads, and thus demand for natural gas, though we expect these loads to be more even throughout the year: U.S. petroleum demand for transportation only varies by ~10% throughout the year, with peak demand in June-August, and lowest demand in January-February (EIA, 2017d).

In the E3 (2015a) “CCS” scenario that closely resembles Scenario A, 0.43 EJ/yr of pure hydrogen (21% of 2015 gas demand) is used to supply energy for transportation and possibly other end uses. This could be provided by dedicated hydrogen infrastructure, on-site generation from electricity, or possibly other sources (e.g., local biomass). Alternatively, some of this demand could be satisfied instead by additional electrification, since both hydrogen and electricity are capable of delivering low-carbon energy solutions, and to some extent can be traded off. For the fossil-CCS scenario, where the majority of electricity generation is provided by natural gas, if electrification substitutes for pure hydrogen end uses, the total gas demand could be higher, because the conversion efficiency to electricity in a natural gas-CCS power plant is ~40% (Rubin et al., 2015), whereas it can be more than 60% in a hydrogen fuel cell vehicle (DOE, 2006).

The need for UGS in winter would increase in Scenario A compared with today, due to:

- Increased reliance on gas for electricity generation, both for CCS and to back up intermittent renewables, which have their lowest output levels in winter.
- Generally higher levels of electricity needed to provide building heat, coupled with lower efficiency of heat pump technologies at lower ambient temperatures.
- Short-term electricity demand for heating during cold-weather events.
- Increased electricity and/or pure hydrogen demand for transportation.
- Given the likely inability of electricity storage, flexible electric loads and other mitigation strategies to reduce the need for extra gas electric generation for more than a few hours at a time, the need for UGS will remain and may grow significantly.

More need for UGS in summer is also likely in Scenario A, due to:

- Somewhat higher electricity use owing to electrification of end uses and a general growth in demand from the present day, but gas demand for electricity will be much higher, because of the high proportion of electricity generated by natural gas with CCS.
- Renewable electricity generation that is higher in summer, reducing the need for gas backup. However, occasional large reductions in output will still occur, requiring backup capacity to be available. This reliance on gas represents an increase from current-day uses of gas to back up renewables, with large and erratic swings in demand possible.

- If P2G is used as an energy storage strategy, it will be used more frequently in summer when intermittent renewable output is highest. This will create additional gas (hydrogen and/or methane) that must be stored.

- Non-electric uses of gas in summer would decrease, as building heating (primarily water heating in summer) shifts from gas to electricity. Because heat pump-based heating is more efficient when ambient air temperatures are high, the shift from gas to electric heating will likely result in net decreases in gas demand for these end uses during mornings and evenings, when demand for heat is highest.

- Other demands for electricity, mainly new uses such as electric vehicle charging and possible hydrogen generation, could increase slightly (~10%) in summer, driving up the overall demand for gas.

- Wildfires are more frequent in summer months, and could represent additional sources of potential generation loss that requires backup.

- Climate change would also increase the demand for electricity and hence gas, and could be amplified by extreme heat and drought events, requiring greater reliance on UGS.

- Overall, more gas use as well as higher peak gas demands will drive up the need for UGS to provide adequate gas supply in summer months.

New pipelines and storage for the management of captured CO_2 (and possibly hydrogen) would also be required in this scenario. While CO_2 management would not impact the need for UGS directly, it would increase California's reliance on storage generally, requiring approval of new storage facilities and the pipelines to carry the CO_2 to them.
The use of hydrogen (e.g., from P2G) would also possibly require new storage and pipeline facilities to manage the gas, if it is not produced from on-site resources (electricity, biomass, etc.).

3.3.3. Scenario B: Flexible, Non-fossil Generation + Building Electrification

This scenario focuses on generation technologies that can provide increased flexibility over intermittent renewables and do not consume fossil fuels. Some of these technologies are described as dispatchable, schedulable, high capacity factor, or baseload generation. While not all equivalent, examples include nuclear, geothermal, biomass, hydropower, marine and hydrokinetic, offshore or high-altitude wind, solar thermal with storage, and potentially other technologies. All of these technologies face one kind of obstacle or another to expansion, be it cost, resource limitation, regulation, or siting. Details of all technologies are discussed in Appendix 3-2: Energy Technologies.

While generation technologies such as nuclear typically operate in a nonflexible or baseload mode, it is possible to operate them flexibly (NECG, 2015): in France, where more than 75% of electricity is produced by nuclear power, many plants operate in load-following as well as frequency-regulation modes in addition to baseload. Moreover, some types of nuclear units such as CANDU reactors in Canada have the capacity to lower electrical output by up to 40% while maintaining full reactor power. The Columbia reactor in the U.S. is also able to lower output by 35% through a combination of control rod and recirculation flow adjustments.

There would likely be a decrease in annual natural gas demand in Scenario B. As for Scenario A, electricity demand would increase as a result of building electrification, electric transportation, and possibly hydrogen generation. A majority (>50%) of electricity generation would come from flexible, non-fossil electricity technologies, with most of the remaining generation coming from intermittent renewables. As a result, much less natural gas would be needed to generate electricity, and there would be a reduced need for load balancing due to the dispatchable nature of the majority electricity generation. While it is difficult to assess how much less gas would be needed for electricity generation, we estimate that significantly less than half of today's electricity gas use might be required.

Like Scenario A, there may be a significant demand for pure hydrogen. If this demand is partly satisfied instead by additional electrification, total gas demand would be lower, because natural gas would be used to provide only a small fraction of electricity in Scenario B.

Scenario B would likely reduce the need for UGS in both winter and summer in this scenario, due to the following:

- Compared with Scenario A, there would be far less reliance on UGS in both summer and winter, because of a much lower fraction of electricity generation produced from natural gas.

- While flexible, non-fossil resources would (like all generation technologies) be more economical if run at maximum output throughout the year, it is possible that such technologies could be ramped over multiple days or seasonally, in order to better balance electricity demand with supply and minimize the need for natural gas generation.

- However, there would still be a need for fast-ramping dispatchable generation, both to deal with demand spikes (in either electricity or direct use of gas) or load balancing of any intermittent renewables in the electricity system, as well as wildfires or climate change-related impacts, which could occur quickly and last over multiple days. UGS could serve this purpose.

Further study should focus on how much flexible, non-fossil resources could be ramped to further reduce reliance on natural gas generation.

3.3.4. Scenario C: Intermittent Renewables + Building Electrification

As for Scenarios A and B, electricity demand will increase due to building electrification, electric transportation, and possibly hydrogen generation. However, because renewables could increase to as much as ~80% of total generation, much less natural gas would be needed to generate electricity, though the need to balance intermittent generation would increase significantly, somewhat moderating the reduction in gas demand. While detailed modeling results for gas demand are lacking, we estimate that perhaps a similar amount of gas as used for electricity generation today would be required. For non-electricity gas demand, we estimate a decrease resulting from increased building electrification.[5] Overall, there would likely be a decrease in annual natural gas demand.

In the E3 (2015a) "Straight Line" scenario that closely resembles Scenario C, 0.47 EJ/yr of pure hydrogen (23% of 2015 gas demand) is used to supply energy for transportation and possibly other end uses. Like Scenario B, if electricity rather than pure hydrogen is used for some end uses, total gas demand would be lower, owing to the small fraction of electricity produced with natural gas.

The need for UGS in the winter could increase or decrease in Scenario C, due to the following:

- Like Scenario B, there would be less reliance on gas for electricity generation, but more reliance on gas to balance renewable intermittency, particularly in winter when renewable capacities tend to be lower. While gas demand could be lower, the reliance on UGS might actually increase.

- Depending on how much electricity storage, flexible electric loads, regional coordination, building thermal storage, and other mitigation strategies are available in this scenario, the overall need for UGS could be similar to or less than today, but as noted earlier, the multiple-day generation deficits from intermittent renewables will almost certainly drive up the need for UGS relative to the present on certain days.

The need for UGS in the summer could increase or decrease in Scenario C, due to:

- Higher electricity demand in summer resulting from increased electrification, but overall gas demand will be much lower, resulting from the lower share of electricity generated by natural gas.

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5. An alternative approach (e.g., Mathieson et al., 2015) uses waste heat from renewable sources (mainly biomass and solar) to provide district heating in lieu of either natural gas combustion or electricity for heating. However, the infrastructure requirements of such an approach would be large. The consequences would be further lowering of gas use, making UGS requirements more comparable to those in Scenario B.

- Renewable generation will be higher in summer, but occasional large reductions in output would still occur, requiring gas backup capacity. P2G, if used, will be most heavily used in summer, providing additional gas that must be stored.

- Likely net decrease in gas use from building electrification, due to the small fraction of gas used to make electricity and the higher efficiency of heat pump-based heating in summer.

- Very small increase in demand due to vehicle electrification and possible hydrogen generation.

- Wildfires and climate change could create additional generation losses, requiring more UGS to provide backup capability.

- Overall, although some amount of UGS would still be needed, it is not possible to determine whether the need for this capacity will be higher or lower than present day in summer.

More detailed modeling of the coupled gas-electricity system at the hourly level will be needed to better help understand whether additional UGS would be needed for this scenario. Such modeling capability could be especially valuable if embedded in new planning and forecasting systems.

3.3.5. Scenario D: Intermittent Renewables + Low-carbon Gas

Annual demand for natural gas would be similar to today in this Scenario. Gas would be used much as it is today, but with much lower GHG emissions. Low-GHG substitutes for natural gas include biomethane, SNG, and hydrogen, all of which would be blended with natural gas in pipelines. While this scenario would have similar levels of electricity load balancing as in Scenario C, it would require much less building electrification, because it can burn low-carbon gas for heat. As a result, the total demand for electricity is lower, which lowers the gas demand for electricity generation. With population and economic growth, the demand for non-electricity gas increases, but with increased renewable generation and a general increase in efficiency, total gas demand remains about the same as today.

Unlike Scenarios A through C, there is less of a need for either electrification or pure hydrogen for transportation in Scenario D, because low-carbon natural gas is available as a fuel. However, if either of these alternatives are used in place of natural gas for transportation, total gas use would likely decrease, because energy conversion in natural gas turbines (MIT, 2010) or hydrogen fuel cell vehicles (DOE, 2006) is roughly twice as efficient as in conventional natural gas vehicles.

The need for UGS in the winter could increase or decrease in Scenario D, due to:

- Less reliance on gas for electricity generation, but more reliance on gas to balance renewable intermittency. The overall need for UGS is less than in Scenario C, because there is less total electricity demand.

- Slightly higher reliance on UGS to provide gas for non-electricity demand than today, particularly during cold weather events when the demand for gas-supplied heat is high.

- Slightly increased electricity demand, and hence gas, from electric vehicles, but as there is less electrification overall, this demand would be unlikely to exacerbate peaks in natural gas delivery.

The need for UGS in the summer could increase or decrease in Scenario D, due to:

- Slightly higher demand for electricity in summer, but gas demand will be much lower than today, due to the lower share of electricity generated by natural gas.

- As for Scenario C, renewable generation will be higher in summer, but occasional large reductions in output still occur, requiring gas backup capacity. P2G, if present, will be most heavily used in summer, providing additional gas that must be stored.

- Slightly higher gas demand for non-electricity heating.

- Very small increase in demand due to vehicle electrification.

- Wildfires and climate-change-driven generation losses could require more UGS for backup.

As for Scenario C, more detailed modeling of the coupled gas-electricity system at the hourly level will be needed to better help understand whether additional UGS would be needed.

3.3.6. Summary of 2050 Scenario Assessments

Table 5 summarizes our assessments for 2050.

For three of the four scenarios in Table 5 (all but Scenario B), E3 (2015a) provided cost assessments as well as build-out rates, which are summarized in Appendix 3-4: Scenario Feasibility Assessment.

While the data used for the cost assessments are likely now out of date, E3's comparison of total system costs for various scenarios, including different requirements for back-up power, transmission and construction, concluded that the CCS scenario (which closely resembles

Scenario A) was the least expensive, while the low-carbon gas scenario (which closely resembles Scenario D) was the costliest. Since then, the prices of both renewable generation and natural gas have fallen, though gas prices could increase in the future.

Finding: The maximum rate of deployment of CCS technology exhibited in any scenario is well below the maximum historical rate seen for U.S. expansion of nuclear and natural gas capacities, normalized for California, but the scale-up rates of wind and solar in scenarios which maximize these resources may be close to the historical maximum.

Appendix 3-4: Scenario Feasibility Assessment also provides an assessment of the amount of biomethane required in Scenario D, concluding that it would represent an unprecedented increase over target levels in other countries such as Europe, and while the technical resource exists within the U.S., California would have to import a significant share because the in-state resource is inadequate. Moreover, it would require significant technology development as well as expansion of portions of the national pipeline system, as very little available biomass is currently converted into biogas for biomethane production.

The decisions to pursue significant amounts of CCS and/or low-carbon gas, as represented by scenarios A and D, respectively, are important forks in the road for future California climate policy. Scenario A would greatly increase the State's reliance on natural gas as well as require significant new infrastructure to handle CO_2 destined for underground storage. By contrast, Scenario D would greatly increase the State's dependence on non-fossil sources of methane, particularly biogas. Both would require a continued reliance on UGS. On the other hand, not pursuing either of these options (e.g., scenarios B or C) might lessen California's dependence on UGS. However, Scenario C would still require grid reliability at multiday to seasonal time scales, and natural gas appears to be the only viable option; thus, in this scenario, the overall need for UGS might remain similar to today, or even increase. Only Scenario B appears poised to significantly reduce California's dependence on UGS.

Finding: Meeting seasonal demand peaks and daily balancing, including backing up intermittent renewables are important issues for reliability and these in turn will determine the future need for UGS.

Finding: Future scenarios of the energy system indicate that adding more inflexible and intermittent resources similar to those in use today will challenge reliability and require many fundamental changes to the energy system. Future energy system choices with less intermittent resources will be closer to the current energy system, but will require a wider variety of resources than are currently contemplated in California.

Conclusion 3.10: Future energy systems that include significant amounts of low-carbon, flexible generation might minimize reliability issues that are currently stabilized with natural gas generation.

Recommendation 3.3: California should commit to finding economic technologies able to deliver significantly more flexibility, higher capacity factor, and more dispatchable resources than conventional wind and solar photovoltaic generation technologies without greenhouse gas emissions. These could include biomass, concentrating solar thermal; geothermal; high-altitude wind; marine and hydrokinetic power; nuclear power; out-of-state, high capacity factor-wind; fossil with carbon capture and storage; or another technology not yet identified.

Conclusion 3.11: *Widely varying energy systems might meet the 2050 climate goals. Some of these would involve a form of gas (methane, hydrogen, CO_2) infrastructure including underground storage, and some may not require as much UGS as in use today.*

Recommendation 3.4: California should evaluate the relative feasibility of achieving climate goals with various reliable energy portfolios, and determine from this analysis the likely requirements for any type of UGS in California.

Conclusion 3.12: California has not yet targeted a future energy system that would meet California's 2050 climate goals and provide energy reliability in all sectors. California will likely rely on UGS for the next few decades as these complex issues are worked out.

Recommendation 3.5: A commitment to safe UGS should continue until or unless the State can demonstrate that future energy reliability does not require UGS.

3.4. WHAT HAS TO HAPPEN BY 2030 TO BE PREPARED FOR 2050

In order to reach any of the 2050 scenarios described above, California must begin making changes in the near term (e.g., between now and 2030) in order to facilitate the significant transition of its energy system. Some of these are already under way, such as the increase in California's renewable electricity share from 33% by 2020 to 50% in 2030 (60% if SB 100 becomes law; CALI, 2017), doubling the rate of building efficiency improvements between now and 2030 (SB 350), or installing more energy storage (AB 2514).

Generally speaking, the siting, permitting, and construction process for major infrastructure projects in California, including electric transmission lines, gas pipelines, CCS-related infrastructure, PHES, electric generating plants, and UGS, can take at least 10 years and quite possibly longer. Therefore, in most of what is discussed below, we assume a 10-year planning horizon for any new resource that must be available by a certain year.

3.4.1. Elements That Decrease Demand for UGS

3.4.1.1 Flexible, non-fossil electricity

In order to develop significant capacity of flexible, non-fossil electricity generation, a commitment to developing technologies other than conventional wind and solar photovoltaic generation technologies—whether those are biomass, concentrating solar thermal, geothermal, high-altitude wind, hydro, marine and hydrokinetic power, nuclear, or another technology not yet identified—must accelerate, beginning with a focused research effort over the next few years. This is because it will take time to analyze and develop technologies that are not yet technically mature, before pilot plants can be deployed, let alone large-scale build-out. Many of these technologies have been explored with federal research funding (see Appendix 3-2: Energy Technologies).

The CEC's Electric Program Investment Charge (EPIC) is a good example of a mechanism to direct and fund this type of research at the state level, but a roadmap for the long-term development of flexible, non-fossil resources should be completed as soon as possible, with the aim of identifying possible locations for developing these resources, as well as locations of future transmission capacity. Out-of-state resources should also be identified, and pursued if attractive. In order for these technologies to play a significant role by 2050, demonstration plants should be built in the 2020s and completed before 2030. Approvals for large-scale build-out would be needed soon thereafter, in order to ramp up beginning no later than 2040. Stimulating confidence in these technologies will be necessary to encourage the financial sector to make the needed investments.

3.4.1.2 Load balancing without using natural gas

Because of the greater challenges of balancing renewable intermittency common in all scenarios, as well as the need for some load balancing of slow-ramping dispatchable generation technologies, resources including electricity storage, flexible loads, increased transmission capacity, and regional electricity coordination will be especially important to identify early in the process. California's Energy Storage Roadmap (CAISO, 2014a) offers a useful starting point for storage technologies, and encompasses planning, procurement, rate treatment, interconnection, and market participation activities across several State agencies. The California Vehicle-Grid Integration Roadmap (CAISO, 2014b) focuses on the use of electric vehicles to perform load balancing and other grid services through determination of value and potential, development of enabling policies, regulations, and business practices, and support for technology development. CAISO's analysis of expanded renewables generation under SB 350 discussed the benefits of a regional electricity market to increase reliability and lower the cost of renewables integration (Pfeifenberger et al., 2016). SB 338, enacted in September 2017, directs California utilities to consider the GHG emissions of peak demand electricity generation (Trabish, 2017) and represents a step in the right direction.

A broad focus, encompassing all non-gas-based load-balancing technologies, and consisting of research, pilot plant construction, regulatory frameworks, financial incentives, and build-out plans, will be required to develop the necessary levels of capacity to maximally reduce GHG emissions. Because many complementary technology options may be available, an emphasis on performance metrics rather than prescriptive technologies should be pursued, to allow market forces to determine the best mix of technologies to satisfy future needs. This work must get under way today, in order for sufficient resources to be available when they begin to be needed in the 2025-2030 timeframe.

However, these technologies cannot eliminate the need for UGS (whether the stored gases are primarily fossil natural gas, biomethane, SNG, or hydrogen), because absent a technical breakthrough, they cannot cost-effectively provide multiday storage capacity. See discussion under 3.4.3. Elements That Increase Demand for UGS on development needs of those technologies.

3.4.2. Elements with Unclear Impacts on UGS

3.4.2.1 Vehicle electrification

To the extent that natural gas will play a role in future electricity generation, the use of electric vehicles could increase demand for natural gas. However, flexible vehicle charging, if implemented effectively, could lower overall electricity ramping requirements, reducing the need for natural gas and possibly UGS. Therefore, the impact of vehicle electrification on natural gas demand and UGS is unclear (Forrest, 2016). Currently, electric light-duty vehicles are enjoying high growth rates and lavish media attention, with good reason: battery costs are falling rapidly, driving ranges are increasing, and costs are quickly becoming affordable to a broader range of Californians. The Governor's Zero Emission Vehicle (ZEV) Action Plan is helping drive adoption toward 1.5 million vehicles on the road by 2025 (IWG, 2016), which is an ambitious near-term target. However, electric vehicles will need additional support from the State to succeed in the market, with adequate charging infrastructure, interoperability standards, reasonable electricity rates, and the ability for vehicles to provide load-balancing services when desirable. The California Vehicle-Grid Integration Roadmap (CAISO, 2014b) is tackling many of these issues, but a long-term roadmap consistent with 2030 and 2050 GHG policy will also be needed by 2020, to continue to drive the needed infrastructure investments.

Expansion of electrification into other parts of the transportation sector, including medium- and heavy-duty vehicles, buses, rail, and marine ports, is also desirable and encouraged. While the State has developed policies to encourage this development, namely through its Mobile Source Strategy and Sustainable Freight Action Plan (see Appendix 3-3: Recent Federal and State Policies), more should be done to provide a long-term research, development, and deployment roadmap, with goals established by 2020 to support targets in 2030 and beyond.

3.4.2.2 Intermittent renewable electricity

In order to grow California's renewable electricity generation share significantly beyond the 2020 goal of 33%, the State will have to identify new locations for wind, solar and other forms of renewable energy generation, including possible offshore wind generation locations, as well as transmission capacity to connect this generation to load centers. Out-of-state renewable resources must also be identified and pursued if economically attractive. This process is already under way for those renewable goals that have been established in law (e.g., 50% by 2030), but to reach the even higher targets that may be needed by 2050, the State should be establishing long-term goals as well as planning for expansion significantly beyond 50% renewables, starting in or before 2030.

The combination of intermittent renewable electricity and load-balancing technologies has unclear implications for UGS. On the one hand, increased levels of renewables tend to decrease dependence on natural gas, particularly in summer, when both electricity demand and intermittent renewable output are highest. However, the load-balancing requirements to deal with intermittent renewables on multiple time scales (intraday, multiple-day, and seasonal) are significant, and may require heavier reliance on UGS than at present, if largely supplied by gas-based technologies.

A research agenda consisting of detailed simulation of both the electric and gas systems on an hourly basis in California, with spatial granularity sufficient to resolve differences in renewable generation, transmission bottlenecks and gas propagation, will be required.

3.4.2.3. Building electrification

In order to significantly increase the fraction of buildings (and industrial facilities) using electricity rather than natural gas for heating, the State will need policy mechanisms in place soon to encourage this transition. Buildings have very long lifetimes, typically more than 50 years, so turnover rates are slow. Therefore, policies must be put in place now to have sufficient impact over several decades. Currently, the only mechanism we are aware of to increase building electrification is the zero-net energy building policy, which goes into effect for new residential construction in 2020 and commercial construction in 2030, and is being implemented through changes in Title 24, California's building code. The zero-net energy building policy is still in development, but currently plans to offer compliance for new construction through either all-electric or mixed-fuel (gas + electricity) designs. However, the vast majority of California buildings will not be affected, because annual new construction represents a small fraction (~1%) of total building stock. We recommend stronger policy mechanisms to encourage electrification of both new and existing buildings be introduced, beginning by 2020. We also recommend research on the cost-effectiveness of different electric technologies in the near term and periodically, to better guide the selection of feasible targets.

While building electrification generally results in lower utilization of gas, the combination of less efficient heat pumps during winter and short-term spikes in demand during cold-weather events could cause an increased reliance on UGS. Moreover, for an electricity system heavily dependent on gas-based generation, such as for Scenario A (fossil-CCS), gas use and hence UGS could increase relative to today.

Detailed simulations of the use of building electrification technologies in combination with electricity generation and gas delivery on an hourly basis is required, using a modeling framework similar to what is proposed above under *3.4.2.1 Intermittent renewable electricity*.

3.4.3. Elements That Increase Demand for UGS

3.4.3.1. Low-carbon gas

A commitment to low-carbon gas (through a combination of biomethane, SNG, and/or hydrogen), whether providing a small or large portion of the gas used in 2050, must start with identification of likely resources and technologies, some preliminary work for which has already been done (e.g., Murray et al., 2014; Williams et al., 2015). This work must continue over the next few years, and by 2020, goals for production over the coming decades should be established in order to begin the planning process.

For biomethane, while some resources are available in-state, it is very likely that California will have to procure out-of-state resources for the majority of its supply, so relationships with biogas-rich states will need to be developed in the next few years as well. If biomethane proves viable, there may be substantial competition for this resource as other regions adopt similar goals.

Before firm plans can be made for hydrogen, it will be important to have a thorough understanding of blending limits, the costs of system upgrades to increase those limits, as well as current and future costs of production (in collaboration with federal research programs; e.g., U.S. Department of Energy (DOE); but these should be solidified as soon after 2020 as possible in order to provide sufficient time for development and deployment.

In all cases, further technology development leading to cost reduction will be essential in order to make a low-carbon gas future economically feasible. Early investment in research and development in collaboration with other states, the federal government, private companies, international institutions, and other interested stakeholders will be essential to realize these goals. Forming a coalition, with members invited from each of these sectors, to tackle these challenges may be a useful strategy.

3.4.3.2. Power-to-Gas (P2G)

P2G technologies are still in a developmental stage, with P2G-hydrogen likely the most mature at present, with projected costs of ~$1/kg hydrogen by 2030 (Ferrero et al., 2016), equivalent to ~$7.5/MMBtu. However, P2G-methane could potentially be a more useful technology in the long run, due to the compatibility with existing pipeline networks, and the challenges of managing and blending large amounts of hydrogen in those networks. As an element of an energy storage portfolio to reduce the use of fossil natural gas, P2G could play a vital role in the future, especially when coupled with high levels of intermittent renewable electricity generation, because it has the ability to convert “excess” electricity into chemical fuels that can be stored cheaply and indefinitely in very large amounts, unlike almost all other storage technologies. P2G creates a greater need for UGS, however, by generating gases that must be stored.

In order for any P2G technology to be available for widespread use by the 2040s, research under way now must be augmented to pave the way for commercial demonstrations in the next decade. Potential synergies between P2G-methane utilizing CO_2 from low-GHG sources, and CCS technologies exist, and should be researched more thoroughly. Linkages between state energy storage, low-carbon gas and CCS roadmaps should be made, along with research objectives at both the CEC and federal agencies.

For more information on P2G, see Appendix 3-2: Energy Technologies, Power-to-Gas.

3.4.3.3 Fossil-CCS electricity

Although the federal government (and international community) has been leading CCS[6] research, development and demonstration efforts for many years, California must pursue its own agenda of technology advancement of fossil energy technology with CO_2 capture in order for CCS to play a significant role in the State's 2050 electricity system. This agenda must include further research, pilot plant construction, regulatory frameworks, financial incentives, and ultimately a roadmap for build-up of generation capacity with CCS. According to E3 (2015a), fossil-CCS capacity would need to begin coming online in 2040, which means that the planning process must be well under way by 2030 in order for this technology to be a major contributor in 2050. Pilot plants, necessary to gather early operational experience, have been built in a few locations in the U.S. and elsewhere (see Appendix 3-2: Energy Technologies, Carbon Dioxide Capture and Sequestration), but will also need to be built in California by 2025 in order for there to be sufficient time to make use of lessons learned in the planning process for full-scale deployment. Therefore, the planning process for these pilot plants, as well as the research to support them, should essentially be under way today.

Simultaneous with this effort, the State must develop a roadmap for siting and construction of CO_2 pipeline and underground CO_2 injection capacity, both in-state and in collaboration with neighboring states, since it is likely that at least some of the CO_2 storage capacity will need to be located out-of-state. This process must also be well under way by 2030, and much sooner at small scale to support pilot plants that will be needed in the 2020s. It may also create competition for underground storage sites among natural gas, hydrogen, and CO_2 uses, which could require a new type of approval process that ranks potential sites by their value in storing each of these gases.

Identification of industrial facilities other than electricity generation that would be amenable to CCS technology, such as fossil- or biomass-based fuel production plants, cement manufacturing plants, and other large-scale facilities, should be completed by 2030, along with policies to encourage the development of CCS capabilities in these sectors. Near-term opportunities to lower costs, by utilizing captured CO_2 for other purposes such as enhanced oil or gas recovery, should also be identified before 2030.

While less important than for intermittent renewable electricity, increased load-balancing resources to complement slow-ramping fossil-CCS generation that are not based on natural gas must be identified and quantified as functions of future electricity generation capacity and loads, and plans made to research and procure such resources well in advance of their actual need. See 3.4.1.2 Load balancing for more information.

6. Many researchers and advocates of CCS now refer to the technology as "CO_2 capture, utilization and sequestration" (CCUS), in order to highlight opportunities for using CO_2 and not simply storing it. While we acknowledge the potential for CO_2 utilization and consider the terms CCS and CCUS to be interchangeable, we focus on the storage challenge in this report.

3.4.3.4. Hydrogen vehicles

To support the long-term deployment of hydrogen vehicle technology, California's current hydrogen vehicle plans (IWG, 2016; CalEPA/CARB, 2016) must be augmented by 2020 to identify further development needed for 2030 and beyond, including plans for providing and managing the demand for low-GHG hydrogen through a possible hydrogen pipeline and underground storage network. This will need to be done in conjunction with planning for the future of UGS, since a reduction in UGS and associated pipelines for natural gas could free up resources for use with hydrogen.

3.4.3.5 Natural gas vehicles

Increases in natural gas vehicles (NGVs) will require a thorough understanding of the GHG impacts and trade-offs against other transportation options that might have lower GHG emissions. This work needs to take place now. Moreover, significant increases in NGVs on California's roads will impact natural gas demand and possibly UGS, so a research, development, and deployment roadmap that is synchronized with other transportation decarbonization plans must be developed by 2020, to avoid pursuing policies that operate at cross-purposes with other GHG goals.

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Appendix 3-1: Scope of Key Question No. 3

Subtask 3.1

What do changes in the energy system and possible changes anticipated to meet California's 2030 and 2050 climate goals imply for future gas usage and the need for gas? How might deployment of new technology impact the need for storage? In particular, what alternatives can feasibly replace or compete with gas storage in the deployment and integration of intermittent renewable energy? What practical economic and environmental impacts might these alternatives incur?

Subtask 3.1.1: Perform a literature search on prior studies of 2050 GHG reduction pathways in California and elsewhere, and obtain the corresponding natural gas data (or qualitatively estimate it from information about the study and interaction with study authors)

- Subtask 3.1.2: Examine FERC mandates for natural gas storage, CARB long-term plans (beyond 50% RPS), other recent mandates, and major technology developments that could have an impact on storage scenarios

- Subtask 3.1.3: Categorize scenarios according to the future demand for gaseous fuels, considering both absolute amounts and temporal distributions of demand

- Subtask 3.1.4: Develop qualitative descriptions of how natural gas storage and infrastructure would change under each identified scenario, and qualitatively characterize the costs

Subtask 3.2

How could coordination of gas and electric operations reduce the need for storage? How may regional coordination of electric grid operation and planning change the role of gas/electric coordination and use of infrastructure?

- Subtask 3.2.1: Examine current and potential future coordination of gas and electric operations by CAISO

- Subtask 3.2.2: Identify how the future developments considered above could impact the scenarios identified and categorized in 3.1

Subtask 3.3

What does the assessment of storage that might be required to meet 2050 goals imply about storage in the interim time period?

- Subtask 3.3.1: For each major natural gas usage scenario identified in 3.1, consider pathways that might exist along the way to GHG compliance in 2050
- Subtask 3.3.2: Characterize interim stages of natural gas infrastructure changes, with particular attention focused on the 2030 GHG compliance year

Appendix 3-2: Energy Technologies

In this Appendix, we review the major technology components needed to achieve overall low GHG emissions for the California energy system in order to assess the need for UGS. Note: some of the materials in this section are based on content developed for Greenblatt et al. (2017b).

Wind Energy

Conventional wind power

Installed wind power capacity has more than doubled globally since 2010, reaching 433 GW by the end of 2015 (GWEC, 2016). The U.S. has the second-largest installed capacity of wind power at 74 GW, right behind China. U.S. capacity is forecast to grow to 91-107 GW in 2020, 118-218 GW in 2030, and 138-297 GW in 2040, depending on policy assumptions (OECD/IEA, 2015). In California, installed wind power was 5.66 GW as of the first quarter of 2017, ranking fourth behind Texas, Iowa, and Oklahoma. The estimated technical potential for wind power in California is 66 GW at 110 m hub height (AWEA, 2017). The average capacity factor for conventional wind power in 2016 was 35% (EIA, 2017e).

Wind turbine installed costs in the U.S. have fallen ~20-40% relative to a 2008 high of \$1,500/kW in 2015, due in part to increases in hub heights and rotor diameters that have reduced project costs and wind power prices. Average 2015 installed costs were ~\$1,000/kW (Wiser et al., 2016a). An extensive expert elicitation study of future wind energy costs found that relative to 2014, the levelized cost of energy[7] could fall 24-30% in 2030 for both onshore and offshore technologies (Wiser et al., 2016b).

7. We define "levelized cost of energy" as the net present total ownership cost (including capital, financing, taxes, operations and maintenance) divided by the total energy output over the life of the equipment (typically 20-40 years). It is sometimes abbreviated as LCOE. It does not usually include subsidies or other market incentives.

Floating offshore wind turbines

A 2016 NREL study showed that California's technical offshore wind resource potential is 112 GW. Unlike the Atlantic continental shelf, the Pacific shelf depth increases very quickly with distance from shore, so that conventional offshore wind turbine moorings are impractical, creating the need for floating wind turbines. This is also the case for California, where almost all offshore resources are located in waters with depths greater than 60 m (Musial et al., 2016). The number of working prototypes around the world for floating offshore turbines is rather small, but the floating offshore wind market appears to be growing. The collaboration between Statoil and Siemens has yielded the Hywind project that will begin in late 2017, constructing a 30 MW wind farm off the Scottish coast (James and Costa Ros, 2015). This will be the first floating offshore wind farm in the world, and will demonstrate if electrical, technical, and infrastructural challenges can be overcome.

Besides these challenges, which include addressing the right platform to make a turbine stable, mooring and anchor design, and high voltage dynamic cables, the main barriers for floating wind turbine installation are high capital and operating expenditures. Mone et al. (2017) estimated a 2015 levelized cost of energy of $181/MWh for fixed-bottom offshore wind turbines, and $229/MWh for floating offshore wind turbines. Beiter et al. (2016) estimated that the current levelized energy cost of floating wind turbines is ~16% higher than conventional fixed-bottom turbines, but by 2030, offshore floating wind turbines will be lower than that of fixed-bottom turbines. EIA (2017f) estimated that offshore wind turbine costs overall will fall to $157/MWh by 2022 and $129/MWh by 2040.

Capacity factors for global offshore wind plants have been slowly but steady increasing. The majority of the plants in 2014 had capacity factors between 35% and 55% (Hahn and Gilman, 2014).

High-altitude wind

High altitude wind represents a potentially game-changing technology, as wind speeds are much higher and more constant above 250 m, and available almost anywhere on Earth. However, harnessing this resource requires a fundamentally different approach than ground-based wind turbines: an airborne energy harvester, as conventional tower designs become prohibitively expensive at these altitudes. Mearns (2016) provides an excellent review on this topic. Two complementary approaches currently exist: (1) airborne energy conversion with electrical transmission to ground via conductive wire, and (2) ground-based energy conversion with mechanical transmission via tether. Two leading companies, Makani (x.company/makani/) and KiteGen (Ippolito, 2010), have designs resembling an airplane wing with multiple propellers, and a large kite, respectively; other companies with variant designs also exist (Mearns, 2016). Both approaches keep aloft utilizing some harvested energy.

Concepts are still in development, but appear technically sound due to advances in sensor, global positioning system, and computing technologies; the main challenge is safety (Mearns, 2016). While high-altitude wind cannot provide baseload power, it delivers much higher capacity factors than conventional wind turbines. It is too soon to determine potential costs, however.

Solar Energy

Solar photovoltaics

Solar electricity today is dominated by photovoltaic (PV) technology of various types, including mono- and polycrystalline silicon (c-Si), gallium arsenide (GaAs), III-V multijunction, and thin-film designs (Bolinger and Seel, 2016; MIT, 2015). In the U.S., c-Si made up 94% of the 2014 market, with thin-film cadmium telluride (CdTe) comprising most of the remainder (Jones-Albertus et al., 2016). GaAs is inherently more efficient than c-Si but also much more expensive; it is usually reserved for high-performance applications.

Global solar PV capacity was 227 GW in 2015, having expanded nearly 10 times over the previous decade earlier, with installations spread across China, Japan, the U.S., Europe, and new markets around the world (REN21, 2016). California leads the U.S. with the most installed solar PV capacity, currently at 7.38 GW (openpv.nrel.gov/rankings). Solar PV capacity across the U.S. was 27 GW in 2015, and is projected to grow to 68-78 GW in 2020, 117-206 GW in 2030, and 169-355 GW in 2040, depending on policy assumptions (OECD/IEA, 2015).

While PV can be as small as a few kW installed on residential rooftops, it is much more affordable at larger scales. For all scales, however, solar PV has seen a tremendous decrease in installed cost since 2009, falling in the U.S. by more than 50% to between ~\$2/W_{DC} (≥500 kW) and ~\$4/W_{DC} (residential-scale). This drop has been mainly precipitated by the large decrease in module prices, which for residential PV fell from ~\$4/W_{DC} average in 2000-2008 to ~\$0.5/W_{DC} in 2015 (Barbose et al., 2016; Bolinger and Seel, 2016), though the ongoing Suniva/SolarWorld trade case may raise these floor prices in the U.S. to nearly \$0.8/W_{DC} (Johnson and Pyper, 2017). EIA (2017f) projects that the levelized cost of energy of utility-scale solar PV will fall from an average of \$78/MWh in 2019 to \$69/MWh by 2040.

The average capacity factor for solar PV in 2016 was 27% (EIA, 2017e).

Solar thermal

Also known as concentrating solar power (CSP), this approach represents a fundamentally different way of harvesting solar energy: using concentrated solar energy as a thermal source driving a steam turbine, much like a conventional fossil-fueled power plant. CSP must inherently track the sun, and pointing stability is critical to maintain high operating temperatures. While CSP plants can store thermal energy for hours, providing dispatchable power, they are only suitable in regions with high direct insolation, and are currently costlier than PV (MIT, 2015). Largely experimental until recently, seven commercial CSP plants totaling 1.4 GW are now operating in the U.S. in Arizona, California, Florida and Nevada (Bolinger and Seel, 2016), using a mixture of single-axis (parabolic trough) and two-axis (tower) concentration designs. Global CSP capacity was 4.8 GW in 2015 (REN21, 2016). However, while prospects are not as promising now due to lower solar PV costs, they are expected to improve in the longer term (OECD/IEA, 2015).

EIA (2017f) estimated that the solar thermal levelized cost of energy will be $218/MWh in 2019, falling to $204/MWh in 2040.

The average capacity factor of solar thermal in 2016 was 22% (EIA, 2017e).

Geothermal Energy

Conventional geothermal energy

Geothermal energy is produced in high-temperature regions at shallow depths (typically >1 km), using either natural or injected water to extract heat from rock. This heat originates from residual energy of Earth's formation supplemented by natural radioactive decay (Ellabban et al., 2014). The undiscovered geothermal resource potential in the U.S. has an electrical power generation mean value of 30 GW (Williams et al., 2008), while in California, it is estimated that there is a potential for at least 4 GW of additional geothermal electricity generation in Imperial, Inyo and Mono counties using current technologies (CEC, 2015).

Conventional geothermal technologies require steam above 150°C for economic operation. However, DOE has been funding research to utilize lower temperatures and/or coproduced resources (hot, non-aqueous fluids such as oil or gas) for electricity generation. In some cases, lower-temperature fluids can improve plant economics by including a value-added secondary application (GTO, 2016).

EIA (2017f) estimated that geothermal will cost $47/MWh in 2022 and $57/MWh in 2040.

The average capacity factor for conventional geothermal power in 2016 was 74% (EIA, 2017e).

Enhanced geothermal systems

The CEC's (2015) assessment of California's geothermal energy potential increases up to 48 GW if enhanced geothermal systems (EGS) technology is introduced (Williams et al., 2008). Comparing to conventional geothermal systems, EGS is an engineered reservoir where hot, dry rock is fractured to increase its permeability and water is injected into it to carry away thermal energy. The natural permeability of rock in EGS candidate reservoirs is typically low and must be improved. Drilling through low-permeability hard rocks with current mechanical drilling technology that easily wears out is not economical, yet these formations often hide the best sources of geothermal energy.

Recent advances in laser power transmission technologies promise to expand the adoption of geothermal energy. ARPA-E funded Foro Energy (based in Colorado) to develop a laser-assisted drilling system that can cut through extremely hard rocks. This system uses advances in cheaper, more powerful lasers and more efficient fiber optic transmission of laser light to increase drill rates and thus decrease the time of drilling. According to Foro's estimates, their technology could drop the cost of geothermal plants by up to 29% (ARPA-E, 2016).

Mines and Nathwani (2013) estimated the levelized cost of energy of EGS to be between \$134/MWh and \$765/MWh; however, DOE has a goal to lower this cost to \$60/MWh by 2030 (DOE, no date).

Supercritical geothermal systems

Another project that promises to lead to a revolution in the efficiency of geothermal systems is the Iceland Deep Drilling Project (IDDP). The main purpose of the project is to determine if it is economically feasible to extract energy from a magma-enhanced geothermal system. The objective of drilling into the "heart" of a volcano is to reach fluids at supercritical conditions (T > 374°C, P > 221 bar for pure water). Extracted fluids have much more energy than fluids in conventional geothermal wells, and can therefore radically increase power output of a well. For their first well, IDDP reached magma of more than 900 °C at 2.1 km depth. The well has proven to be highly productive and became the world's hottest producing geothermal well, with wellhead temperatures of 450°C (Friðleifsson et al., 2014). At the beginning of 2017, IDDP reached a milestone with their second well, drilling to 4,659 m and reaching desired supercritical conditions (IDDP, 2017).

Hydropower

Conventional hydropower

Worldwide hydropower capacity was 1,064 GW in 2015, led by China, Canada, Brazil, and the U.S. (REN21, 2016; WEC, 2016). In developed countries such as the U.S., most significant hydropower resources are already exploited; U.S. capacity is expected to grow modestly from 80 GW today to 93 GW in 2050, with ~50% growth from repowering existing facilities (DOE, 2016). Almost all forecasts of future California hydropower generation keep generation flat at current capacities of ~14 GW. California typically also imports ~4% of its hydroelectricity from the Pacific Northwest (CEC, 2016).

Hydropower is not universally considered "green": in addition to displacing people and habitats when constructing reservoirs, dams may promote anaerobic decay of organic matter, generating the potent GHG methane; recent research suggests this effect could be even larger than previously estimated (Magill, 2014). As a result, California does not count hydropower facilities as renewable unless they are <30 MW (CEC, 2016).

EIA (2017f) estimated that the levelized cost of energy of hydropower will remain essentially flat, falling from $66/MWh in 2022 to $62/MWh in 2040.

The average capacity factor for conventional hydropower in 2016 was 38% (EIA, 2017e).

Marine and hydrokinetic power

Marine and hydrokinetic (MHK) technologies are distinct from hydropower, exploiting energy from waves, tides, and river and ocean currents, and represent a number of potentially viable technologies (www.energy.gov/eere/water/marine-and-hydrokinetic-energy-research-development). The U.S. has estimated MHK's technical potential as ≥ 50% of U.S. electricity demand (OECD/IEA, 2015; www.energy.gov/eere/water/marine-and-hydrokinetic-resource-assessment-and-characterization). However, MHK is still immature and hence expensive, and has recently suffered technological and commercial setbacks (Snowberg and Weber, 2015); while the U.S. and other countries remain supportive (Hydro TV, 2016), the future is uncertain.

The levelized cost of energy for small (10 MW) commercial-scale MHK ranges from $310/MWh to $1,470/MWh (Jenne, Yu and Neary, 2015). DOE has a goal to reduce this cost to $120-150/MWh by 2030 (Duerr, 2014).

Nuclear Power

Conventional nuclear power

While nuclear power in California is currently on a phase-out trajectory, with the 2012 permanent shutdown of San Onofre and the planned closure of Diablo Canyon in 2024, nuclear power capacity remains high elsewhere, with ~100 GW across the U.S. and ~400 GW worldwide (OECD/IEA, 2015), and significant prospects for growth (528-837 GW through 2040, depending on policy assumptions), though almost all operating nuclear reactors in the U.S. will be retired in the 2035-2055 timeframe (Feng et al., 2016) unless replaced with new reactors.

Because nuclear power can be operated at very high capacity factors (typically >90%; EIA, 2017e), it can be challenging to integrate with intermittent renewables; as a result, nuclear must sometimes sell electricity at a loss (Ruth et al., 2014). These economic realities are compounded by relatively inexpensive fossil fuels, such as natural gas, though the most significant economic challenge for nuclear energy is very high construction cost, which contrary to most other electricity generation technologies has tended to increase over time (Grubler, 2010).

There has been a recent outburst of innovation in the nuclear energy sector, with the formation of a number of start-up companies and significant interest in advanced reactors (Greenwood et al., 2016). This interest has been summarized in a report from Thirdway, a nonpartisan think tank (www.thirdway.org/report/the-advanced-nuclear-industry).

EIA (2017f) estimated that the levelized cost of energy of "advanced" nuclear will be $99/MWh in 2022 and $90/MWh in 2040.

Small modular reactors

One example of innovative thinking in the nuclear power field is the increasing interest in small modular nuclear reactors (SMRs) (Martin, 2016), which have been championed by the U.S. Department of Energy (www.energy.gov/ne/nuclear-reactor-technologies/small-modular-nuclear-reactors), as well as investors such as Bill Gates (Muoio, 2016). The U.S. Nuclear Regulatory Commission has recently approved the safety platform of the NuScale SMR (WNN, 2017), the sole U.S. company currently pursuing this technology. SMRs are "theoretically safer" than conventional reactors, "reducing the need for huge containment vessels and other expensive protections" (Martin, 2016). The 50 MW NuScale design, which uses many standard off-the-shelf items, a modular design, and much shorter construction times, is being offered at ~$5,000/kW (NuScale, 2017). However, a recent study by the Union of Concerned Scientists concluded that SMRs would still be more expensive than current reactors, and raised potential safety concerns (Lyman, 2013).

Carbon Dioxide Capture and Sequestration

In carbon dioxide capture and sequestration (CCS), CO_2 that would otherwise be released to the atmosphere during fuel combustion is captured, compressed, and transported to a suitable storage site, where it is injected deep underground and retained in the subsurface through natural trapping mechanisms (Metz et al., 2005, Coninck and Benson, 2014). There are generally three different approaches to integrating CO_2 capture with power generation: pre-, post-, and oxyfuel (or oxy-) combustion:

1. In pre-combustion processes, fuels (typically coal or natural gas) are converted to a mixture of hydrogen and CO_2 via gasification, or reforming combined with the water-gas shift reaction, and the CO_2 is separated from hydrogen, the latter being used as fuel for power generation (Jansen et al., 2015). Integrated gasification combined cycle (IGCC) plants equipped with CO_2 capture, such as the Edwardsport Facility in Indiana (618 MW), are one example of this process (Duke Energy, no date).

2. In contrast, in post-combustion processes, CO_2 is separated from low-pressure flue gas—largely a mixture of nitrogen, water and CO_2—rather than from the fuel (Liang et al., 2015). Post-combustion capture can be applied to conventional

pulverized coal boilers and natural gas combined cycle (NGCC) plants. The most prominent examples of post-combustion capture are the Boundary Dam Power Plant in Canada (110 MW), operating since 2014, and the W.A. Parish Power Plant in Texas (240 MW), which began operation in 2016.

3. The third approach is oxy-combustion, in which coal or gas is burned in a mixture of oxygen and CO_2 rather than air (Stanger et al., 2015). Oxy-combustion avoids the need for a CO_2 separation step, but requires separation of oxygen from air. As of 2016, there were no operating commercial-scale examples of oxy-combustion; however, oxy-combustion of coal has been successfully demonstrated at scales up to 30 MW (Stanger et al., 2015), NET Power developed a 50 MW natural gas demonstration plant that uses an oxy-fuel, supercritical CO_2 power cycle (NET Power, 2016), and cryogenic air separation is fully commercial technology, with thousands of units operating worldwide at equivalent power generation capacities up to 300 MW (IEAGHG, 2007).

The levelized energy cost for natural gas power plants with CCS is estimated to be between \$63 and \$122/MWh (Rubin et al., 2015). Such plants would capture ~90% of emitted CO_2.

CO_2 can be transported by truck, train, ship, barge, or pipeline. All these transport modes are commercially practiced today, although only pipelines are used at scales necessary for CCS from power generation (~1-10 Mt/yr CO_2 per plant). In the U.S., there were ~8,500 km of CO_2 pipelines operating at the end of 2016 (PHMSA, 2017) that, in recent years, moved ~70 $MtCO_2$/yr from mainly natural CO_2 sources for enhanced oil recovery (EOR) (Kuuskraa and Wallace, 2014).

The principal options for geologic CO_2 sequestration are injection into deep brine-filled aquifers, and oil or gas reservoirs (including CO_2-EOR operations) (Coninck and Benson, 2014). The technologies involved in CO_2 sequestration, such as those found in injection wells and used for monitoring, are largely borrowed from oil and gas operations and adapted for use in CO_2 sequestration. CO_2 sequestration has one critical distinction, however: large volumes of buoyant fluid (CO_2) are injected into the subsurface rather than withdrawn. This means that pressure in the receiving formation increases over a large area, and existing brines are displaced away from the injection site (Birkholzer et al., 2015). Thus, pressure build-up limits practical storage capacity in many cases (Thibeau et al., 2014; Bachu, 2015), which has spurred development of pressure management concepts generally (Buscheck et al., 2012), and brine withdrawal plans at the Australian Gorgon sequestration project specifically (Flett et al., 2008). Regulations also recognize the novel aspects of sequestration, typically requiring thorough understanding of site-specific risks (Dixon et al., 2015), which has driven much research into the potential impacts of CO_2 sequestration and risk assessment (Pawar et al., 2015; Koornneef et al., 2012).

According to GCCSI (2016), there are 17 operating large-scale CCS projects worldwide, an additional five currently under construction, and 18 in various stages of development. GCCSI defines “large-scale” as a facility “involving the capture, transport, and storage of

CO_2" at a scale of at least 800,000 t/yr CO_2 for coal-based power plants, or at least 400,000 t/yr CO_2 for other industrial facilities (including natural gas-based power plants). All told, projects expected to become operational by the end of 2017 are estimated to capture ~40 Mt/yr CO_2. In addition, GCCSI lists 78 pilot-scale projects that do not meet the above criteria for large-scale.

The Scottish Carbon Capture & Storage (SCCS) research group also maintains a global database of CCS projects, and in addition to operational, pilot-scale and planned projects, includes >50 pilot projects and ~45 projects in the planning phase, as well as dormant or completed projects (www.sccs.org.uk).

Potential CO_2 storage capacity in California is 30-420 billion metric tons CO_2 across the San Joaquin, Sacramento, Ventura, Los Angeles, and Eel River Basins, according to a 2010 study (DOE-NETL, 2010). In addition, California offshore CO_2 storage capacity amounts to almost 240 Mt CO_2 (Downey and Clinkenbeard, 2011).

Energy Storage

According to SNL (2016), there are nearly 1,600 energy storage projects worldwide that are announced, contracted, under construction, operational, or offline for repairs, with a total capacity of 193 GW. Nearly all capacity is pumped hydroelectric storage (PHES), with electrochemical, electromechanical and thermal providing the majority of remaining capacity. The breakdown by technology type is shown in Table 6.

Table 6. Global energy storage projects.

	Number of projects	Rated power (GW)	Minimum storage capacity (GWh)*
Type of technology			
Pumped hydroelectric	351	183.72	1,718.30
Electrochemical	954	3.19	1.50
Lithium-based	617	2.28	0.38
Sodium-based	72	0.21	0.45
Lead-based	87	0.11	0.05
Flow	91	0.14	0.15
Other/not specified	87	0.45	0.47
Electromechanical	68	2.62	38.51
Compressed air	17	1.59	38.49
Flywheel	49	0.97	0.01
Other/not specified	2	0.05	0.01
Thermal	206	3.62	21.89
Other (mainly hydrogen)	13	0.02	0.07
Breakdown by status:			
Operational	1,323	176.03	1,725.76
Announced	164	12.45	53.43
Contracted	86	3.11	0.04
Under construction	12	1.26	0.02
Offline for repairs	7	0.33	1.01
Total	1,592	193.17	1,780.27

*Note: listed are projects that are announced, contracted, under construction, operational or offline for repairs. Source: SNL (2016). *Not all storage capacities were available.*

For California, there are 284 projects with a total capacity of 7.55 GW. Once again, nearly all capacity is PHES. Table 7 provides a breakdown of energy storage projects by technology and status.

Table 7. California energy storage projects.

	Number of projects	**Rated power (GW)**	**Minimum storage capacity (GWh)***
Breakdown by technology:			
Pumped hydroelectric	11	6.39	148.59
Electrochemical	187	0.62	0.22
Lithium-based	157	0.43	0.05
Sodium-based	5	0.01	0.05
Lead-based	3	0.01	0.01
Flow	8	0.03	0.12
Other/not specified	10	0.15	0.00
Electromechanical	8	0.32	3.00
Compressed air	2	0.30	3.00
Flywheel	6	0.02	0.00
Thermal	78	0.22	1.31
Breakdown by status:			
Operational	201	4.32	144.00
Announced	48	1.32	9.00
Contracted	31	1.76	N/A
Under construction	1	0.01	0.01
Offline for repairs	3	0.15	0.11
Total projects	284	7.55	153.12

*Note: listed are projects that are announced, contracted, under construction, operational or offline for repairs. Source: SNL (2016). *Not all storage capacities were available.*

Battery storage

There are many types of battery storage, including lithium-based, sodium-based (mainly sodium sulfur and sodium nickel chloride), lead-based (mainly lead acid), various kinds of flow batteries (vanadium, iron chromium, zinc iron, zinc bromide, etc.) and others. Lithium-based batteries currently lead both globally and in California for the most projects and capacity of any battery technology. Battery storage durations range from less than one hour to 48 hours (SNL, 2016). Batteries can provide reasonably high power over a time period of minutes to hours, thus making them suitable for both power quality and load-shifting applications. Flow batteries have the advantage that they can be configured for larger energy capacities than other types of batteries, since stored energy is typically in the form of two chemical liquids held in tanks that are, in principle, very scalable. Batteries tend to have smaller rated power capacities than electromechanical or certainly PHES systems.

While some types of battery technologies are well-established (e.g., lead acid, lithium ion, sodium sulfur), many are still under development, and promise lower costs and/or higher performance once mature. The cost of a more mature technology such as sodium-sulfur is ~\$250 to \$300/MWh (Akhil et al., 2013), whereas immature technology can cost >\$500/MWh.

Vehicle batteries could be considered a special form of battery storage. Often connected to the electricity grid for several hours per day (typically outside of morning and evening commuting hours), these storage devices could provide inexpensive storage as they are already paid for by vehicle owners, yet could provide valuable grid services by opting to charge (or even discharge) during periods convenient to the grid operator (Kempton and Tomić, 2005). Presumably, battery owners would have to be compensated for the value of electricity supplied to the grid as well as battery degradation, and a system would have to be created to manage batteries as an aggregate resource.

Thermal storage

This type of storage technology mainly utilizes off-peak electricity to produce chilled water or ice for building air conditioning, though hot thermal storage has also been employed, usually in conjunction with solar thermal plants. Cold storage technologies do not represent two-way storage, but simply a load-shifting strategy; hot storage in conjunction with solar thermal power, by contrast, can be used to generate electricity at a later time. Storage duration ranges from less than one hour to 48 hours, with typical durations of ~6 hours (SNL, 2016).

Pumped hydroelectric storage

PHES is the dominant form of energy storage globally, having begun operation in the 1920s in the U.S. PHES currently comprises 95% of global energy storage capacity, and 85% in California (including all projects regardless of status) (SNL, 2016). PHES employs off-peak electricity to pump water from a reservoir at lower elevation to another reservoir at higher elevation. When electricity is needed, water is released from the upper reservoir to generate electricity using hydroelectric turbines. With the tremendous increase in solar PV capacity in recent years in California, off-peak electricity may be shifting from nighttime (when excess baseload coal and/or nuclear power was often available) to daytime (when solar PV exceeds demand by a considerable margin). Storage capacities range from 2.5 hours to 48 hours, with a small number of projects worldwide with greater capacities. The estimated levelized cost of energy is \$150-220/MWh (Akhil et al., 2013).

There are currently 11 PHES projects in California, including two 500 MW announced projects (Lake Elsinore and San Vicente) and one 1.3 GW contracted project (Eagle Mountain) (SNL, 2016). Expansion of existing PHES capacity is possible; Hall and Lee (2014) identified 31 existing hydroelectric plants in the U.S. meeting various inclusion criteria, with generation capacity of 10 MW or greater, that have the potential for adding PHES. In addition to three new PHES sites that have either been announced or contracted with a total capacity of 2.3 GW (SNL, 2016), six other sites are located in California, with a total generation capacity of 325 MW, and an unknown storage duration potential, and an additional five sites are located in other western states with total capacity of 240 MW. In addition, seven nonpowered dams across the U.S. were identified as PHES candidate sites, with three located in California, and 97 greenfield sites were identified with the potential to construct PHES: 24 located in California with a total potential capacity of >500 MW, and 45 elsewhere in the western U.S. with a total potential capacity of >1000 MW. Even if all of this PHES capacity were developed, it would almost certainly be insufficient to address multi-day *dunkelflaute* conditions, as we have estimated that ~30 GW of generation capacity may occasionally be needed by 2030 to shore up intermittent renewables (see 3.2.4. *Gas Needed to Back Up Intermittent* Renewables in the main text).

Compressed air energy storage

Compressed air energy storage (CAES) uses off-peak electricity to compress air and store it in a reservoir, typically an underground salt cavern or abandoned oil or gas reservoir. When electricity is needed, the compressed air is withdrawn from the reservoir, heated (typically with natural gas), and directed through an expander or conventional turbine-generator to produce electricity. Because natural gas is almost always used in the generation process, CAES is considered a hybrid technology that has non-zero GHG emissions (unless low-carbon gas such as biomethane is used). To avoid burning fuel upon air expansion, the thermal energy of compression must be stored; there is currently one 500 kW demonstration plant in Switzerland able to do this (the Pollegio-Loderio Tunnel ALACAES Demonstration Plant) (SNL, 2016).

CAES was developed in the 1980s, much more recently than PHES, but offers a similar levelized cost of energy ($120-220/MWh) for 5-8 hours of storage (Akhil et al., 2013). Currently, only a handful of plants have been built worldwide; Table 6 lists 17 CAES projects, but only 9 are operational, dominated by one project in Alabama (110 MW) and two in Germany (200 and 321 MW). However, in the U.S. there are also three other operational plants (≤2 MW) and five announced plants (up to 317 MW) including two in California (SNL, 2016). The challenges of siting a suitable underground reservoir, combined with the low cost of gas turbines, has hindered development. The levelized energy cost is estimated to be similar to PHES (Akhil et al., 2013).

Other electromechanical technologies

Besides CAES, most planned or operating electromechanical systems are flywheels, which store kinetic energy as angular momentum of a spinning mass. For safety, flywheels are housed in a containment system that is often placed under vacuum or filled with a low-friction gas like helium to enhance performance. Flywheel systems are capable of very rapid charging and discharging, making them suitable for frequency regulation and applications requiring responsiveness up to a few seconds. Unlike most batteries, flywheels exhibit little performance degradation over more than 100,000 cycles. Sizes range from 10 kW to 400 MW, and cost approximately $400/kWh for 15 min. of storage (Akhil et al., 2013).

Natural Gas Substitutes

Here we discuss the major alternatives to fossil natural gas that would allow the continued use of existing natural gas pipeline and storage infrastructure.

Biomethane

Biomethane is produced from biogas, the byproduct of biological anaerobic decay of organic matter found in municipal solid waste, landfills, manure, and wastewater. Biogas contains ~50% CO_2 and ~50% methane by volume (along with water and some trace contaminants); once the CO_2 and other contaminants are removed, biogas is known as biomethane and can be blended with fossil natural gas in pipelines. As biogas is ultimately of biological (plant) origin, its CO_2 emissions from combustion are offset by CO_2 absorbed during plant growth. Net GHG emissions include additional GHG changes associated with biological processes (changes in carbon stocks, fertilizer application, etc.), as well as fossil fuel combustion during processing and transport.

Resources

In-state biogas resources from landfills, manure, municipal solid waste, and wastewater are limited to ~250 MMcfd (Williams et al., 2015; Jaffe et al., 2016), but costs are very high: ~$10/MMBtu for 100 MMcfd, ~$30/MMBtu for 200 MMcfd and >$50/MMBtu for the full potential (Jaffe et al., 2016). By comparison, current California natural gas average demand is ~6,000 MMcfd, so these resources would provide ~4% of annual demand at most. Another study that includes the hypothetical conversion of all in-state woody biomass waste into biogas estimates that an additional ~550 MMcfd would be available from these resources (BAC, 2014), or another ~9% of current natural gas demand.

Murray et al. (2014) examined sources of biogas across the U.S., and determined that ~3,800 MMcfd could be produced at a cost of ≤$6/MMBtu in 2040, and as much as ~20,000 MMcfd at higher cost (≤$9/MMBtu). Clearly, these national resources are adequate to supply at least a majority of California natural gas demand, and potentially much more. While current natural gas pipeline prices are ~$3/MMBtu, they were well above $6/MMBtu in 2004-2008 and were above $10/MMBtu for four months each in fall/winter 2005 and spring/summer 2008 (EIA, 2017a). Although natural gas production costs may remain low for many years to come, a carbon price of $150/t$CO_2$ recently proposed for 2030 by the CPUC (2017) would increase the effective natural gas price by $8/MMBtu, potentially making biogas more competitive.

Assuming that California imported no more than its population-weighted share of this biogas (currently ~12% of the U.S. population), up to ~2,400 MMcfd would be available, or ~50% of projected 2030 California gas demand (CA Utilities, 2016). However, as a fraction of projected U.S. demand in 2030 under the most recent reference scenario (EIA, 2017b),[8] the maximum biogas potential would represent ~25% of that demand, and may be a more realistic estimate of the fraction of biogas that could be provided to California.

Leakage

According to CARB/CPUC (2017), total natural gas emissions from gas utility facilities in 2015 were 6,601 MMcf, equivalent to ~2.96 Mt/yr CO_2, or about 7.5% of statewide methane emissions in 2014. A top-down revision to California's official methane leakage estimate from California's natural gas system in 2010 is 541±144 Gg/yr (Jeong et al., 2014), or ~1.3±0.3% compared to estimated total natural gas consumption of 43.0 Tg/yr (CA Utilities, 2010). With a 100-year global warming potential of 28-34 for methane (Myhre et al., 2013), this amount of leakage is equivalent to an additional ~11-23 Mt/yr CO_2 in GHG emissions.

It is unknown whether leakage from biomethane production facilities would be higher or lower than from the fossil natural gas system, but this is a significant concern that also needs to be explored.

Treatment and processing

Raw natural gas that is extracted from the ground needs to be cleaned in order to increase its quality for pipelines. Besides methane, which typically contributes 75%-90% by volume, raw natural gas also contains impurities including water, carbon dioxide, nitrogen, hydrogen sulfide, ethane, propane, butane, and some other hydrocarbons (Baker and Lokhandwala, 2008).

To meet pipeline specifications, natural gas is processed at a processing plant to remove impurities. According to www.NaturalGas.org (2013), the process is complex but usually involves four main removal steps:

1. Oil and condensates: If these impurities do not separate on their own, they are separated with a conventional separator where gravity separates heavier oil from lighter gases. If gravity is not successful, pressure is reduced to cool the gas and separate the remaining oil and condensates. These separators use pressure differentials to cool the natural gas, which travels through a high-pressure liquid at a low temperature to separate any remaining oil and water.

8. The EIA reference scenario projects 30.36 quads/yr of natural gas consumption in 2030, or ~80,200 MMcfd.

2. Water: This substance, which would otherwise cause corrosion and other issues, is mostly removed by the above separation methods. The remaining water vapor requires dehydration of natural gas. This treatment consists of either absorption, where a dehydrating agent chemically removes water vapor from the gas, or adsorption, where water vapor is condensed and collected on a surface.

3. Natural gas liquids (e.g., ethane, propane, butane): So-called because they are often pressurized and sold as liquids, these normally gaseous hydrocarbons are removed from natural gas using techniques similar to those for dehydration. While some amounts of higher hydrocarbons in natural gas are permissible (and contribute positively to the overall heating value), at sufficient scale these liquids are often extracted from natural gas and then separated by a process called fractional distillation, an energy-intensive process resulting in high-purity hydrocarbons that can be sold at a higher price.

4. Sulfur and carbon dioxide: Sulfur compounds (particularly hydrogen sulfide) can cause corrosion and can also be lethal to breathe. Called “sweetening” because of the “sour” (acidic) nature of both hydrogen sulfide and carbon dioxide, the process uses an amine solvent to react with and remove the acids, which are then released with heating or partial vacuum, regenerating the solvent. Hydrogen sulfide is removed first, followed by CO_2.

Other impurities can occasionally be present in a raw natural gas, including mercury and nitrogen. In addition to being toxic, natural gas plant operators want to remove mercury because it amalgamates with aluminum (commonly used in heat exchangers), resulting in mechanical failure and gas leakage (Corvini et al.). Nitrogen, on the other hand, lowers the heating value of natural gas and increases transport volumes (Linde, 2016).

Like natural gas, raw biogas is also accompanied by impurities. Raw biogas consists mainly of methane, with about 50% CO_2 by volume. Impurities that are typical for raw natural gas are also common for raw biogas. In addition, biogas may contain ammonia, chlorine and siloxanes in trace amounts, all of which must be removed.

The most commonly used cleaning methods are water scrubbing, pressure swing adsorption, chemical absorption, membrane permeation and cryogenic distillation. The first method removes carbon dioxide (as well as hydrogen sulfide) by taking advantage of the much higher solubility of these gases in water compared with methane. The pressure swing adsorption method removes carbon dioxide, nitrogen, and oxygen by capturing preferred gases in a molecular sieve (or other adsorbing medium) at a high pressure, and then releasing the adsorbates at lower pressure. While impurities are adsorbed, the methane is collected. The third method uses amine solvents to absorb carbon dioxide, as described above for natural gas sweetening. The membrane permeation method uses pressurization, where highly permeable gases, such as carbon dioxide, oxygen, water, travel through a membrane, while low-permeability methane is retained and collected. The last method, cryogenic distillation, was also described above, and takes advantage of the different boiling points of gases (Yang and Li, 2014).

Because of the lower amounts of multiple-carbon containing compounds (ethane, propane, etc.) in biogas as compared with natural gas, its heating value (after removal of impurities) is typically lower than that of natural gas, which can result in a higher volume of gas needed to achieve a given heating task.

Hydrogen

Production methods and costs

There are multiple ways of producing hydrogen: from water via electricity (electrolysis), from fossil or biomass resources (gasification, with steam reforming of methane as perhaps the best-known method), biologically (via microbial conversion), high temperatures (such as found in a nuclear power plant), or even directly from solar energy (photoelectrochemical).

According to Williams et al. (2013), the cost of producing hydrogen from natural gas via steam methane reforming varies from $3.50/kg for small systems to $1.25/kg at large scale, assuming a natural gas price of $6/GJ (~$6.3/MMBtu). Jechura (2015) estimated the cost of steam methane reforming hydrogen at $0.8/kg assuming $4.4/MMBtu and electricity at $68/MWh.

While steam methane reforming is the most cost-effective way of producing hydrogen, this approach emits CO_2 and must be coupled with CCS in order to make it GHG-neutral, increasing costs. Blok et al. (1997) estimated that adding CCS to steam methane reforming incurs a modest (~7%) cost penalty, because the reforming process already produces a concentrated stream of CO_2. In addition, more recent work with chemical looping to improve hydrogen production as well as CO_2 capture efficiency has been proposed (e.g., Martínez et al., 2014). Using hydrogen from biomass would avoid the need to capture CO_2, but it is likely more expensive than using biomethane directly.

Co-production of hydrogen and electricity from coal with CCS was explored by Kreutz et al. (2005); they concluded that hydrogen could be produced for $1.0/kg along with co-produced electricity at $62/MWh with 91% CO_2 capture using an integrated gasification combined cycle/CCS configuration.

For water electrolysis, Jechura (2015) estimated the cost of water electrolysis at $6.8/kg, whereas Ferrero et al. (2016) estimated that alkaline cell technology currently offers the lowest cost of producing hydrogen for grid injection at €3.8/kg (~$4.2/kg), but by 2030, all three technologies are projected to be able to deliver hydrogen for grid injection at €1.0-1.2/kg (~$1.1-1.3/kg). By comparison, the U.S. DOE has set a goal of $2/kg hydrogen wholesale cost in 2020, so this is a very competitive cost, considering that 1 kg hydrogen has the same energy content as 1 gallon of gasoline. However, 1 kg hydrogen is also equivalent to 0.135 MMBtu of natural gas, and at the current price of ~\$3/MMBtu, it will be difficult for hydrogen to compete with an equivalent price of \$0.4/kg.

At elevated temperatures, e.g., 800-1000°C, there is a significant reduction in required electrical energy input, estimated at up to ~30%. Also, conversion efficiencies are significantly higher (up to ~90%). Devices capable of running at these temperatures include solid oxide cells and various hybrid designs utilizing multiple chemical cycles such as sulfur-iodine, sulfur-bromine, sulfur dioxide-sulfuric acid ("hybrid" sulfur), and various metal-halogen cycles, with thermal energy typically supplied by rejected heat from a nuclear reactor (IAEA, 2013). Direct thermochemical decomposition to hydrogen and oxygen is only feasible at temperatures of 2,500°C, which is beyond the range of most industrial processes.

Photoelectrochemical conversion, while promising, is still at an early research stage (Ager et al., 2015).

Hydrogen blending

Hydrogen can be used in various ways. It can be blended with pipeline natural gas to a limited extent; see below for estimates. It can also be used in pure form in vehicles, electricity plants, industrial facilities, and buildings, though the latter use is probably very unlikely due to the challenge of developing a parallel hydrogen pipeline infrastructure to every building, much as natural gas is distributed today.

Hydrogen may require its own pipelines and storage to manage its use, though if capacity is freed up from reduced use of natural gas and UGS, some of it could potentially be repurposed for hydrogen. Alternatively, hydrogen could also be produced on-demand locally from electricity. However, this latter solution could further exacerbate the challenges associated with peak electricity demand periods.

Literature review showed different levels of acceptable hydrogen blending into natural gas pipelines (Altfeld and Pinchbeck, 2013; Melaina et al, 2013; Hodges et al., 2015). Chapter 2 provides additional references of real-world blending experience in the German, French and Dutch gas pipeline systems. The general conclusion is that a safe level of hydrogen is below 20%, and this maximum level should be assessed on a case-by-case basis, because pipeline systems vary considerably as far as pipeline materials, operating pressures, and state of repair. Here we present some technological, environmental and economic issues to be taken into consideration before hydrogen can be implemented on a large scale.

Some elements of the gas system, including many gas turbines, are very sensitive to variations in gas composition. Turbines that can accept more than 50% hydrogen fractions are rather exceptional; the majority of gas turbines can tolerate, after modifications, a maximum hydrogen fraction of 5% to 10% by volume (Altfeld and Pinchbeck, 2013).

Hydrogen embrittlement can damage steels by changing their mechanical properties. The embrittlement depends on many factors, including the hydrogen gas pressure, purity, temperature, exposure time, stress, and strain rate (Barthelemy, 2009). About 97% of natural gas transmission pipeline miles consist of cathodically protected, coated steels (Bipartisan Policy Center, 2014) that are generally not compatible with hydrogen. On the other hand, for more than 50% of distribution pipelines, plastic has become the pipeline material of choice (Bipartisan Policy Center, 2014), which is not susceptible to hydrogen embrittlement. However, some plastics can become brittle with age (Pipeline Safety Trust, 2011), potentially compromising their use with hydrogen. In summary, hydrogen may not be compatible with the vast majority of transmission-level pipelines, and its use in distribution-level pipelines must be approached with caution.

Hydrogen is a much smaller molecule than methane, so its leakage through pipe walls and joints poses safety and environmental risks. Here are some examples:

1. Hydrogen is a flammable gas, and although it is also very buoyant and therefore dissipates quickly, its leakage could pose an ignition hazard (Rusin and Stolecka, 2014). Moreover, hydrogen produces neither visible light nor smoke (Messaoudani et al, 2016). Existing natural gas detection devices also have different detection sensitivities, so they are not necessarily able to detect hydrogen (Altfeld and Pinchbeck, 2013).

2. In the U.S., the most common UGS fields are depleted gas or oil reservoirs (EIA, 2017b). Natural gas/hydrogen mixtures in depleted reservoirs (and also aquifers) could cause bacterial growth. Bacteria that feed on hydrogen can lead to partial or total disappearance of injected hydrogen. Furthermore, there is also a possibility for hydrogen sulfide production (Altfeld and Pinchbeck, 2013).

3. Hydrogen can potentially act as an indirect greenhouse gas because its emissions may decrease ozone concentrations, and increase the lifetime of methane through hydrogen reaction with hydroxyl radicals. Hydrogen has a global warming potential (GWP) of 5.8 over a 100-year time horizon (Derwent et al., 2006), compared to ~30 for methane and 1 for CO_2 (Myhre et al., 2013).

Finally, additional leak detection devices, modified turbines, upgraded domestic appliances, and other sensitive components would likely increase costs for natural gas systems due to increased levels of hydrogen. Van Ruijven et al. (2011) estimate that changing retrofitted natural gas pipelines to hydrogen infrastructure would be 50-80% more expensive.

Hydrogen storage

The three main types of UGS in use today are depleted gas/oil reservoirs, aquifers, and salt caverns. The same type of storage facility that is used for natural gas could be used for hydrogen. However, hydrogen is a small molecule that can leak from most materials, and has a strong chemical affinity to combine with other elements, which could possibly lead to losses or other undesirable issues, summarized as follows:

1. Hydrogen can affect salt permeability if gas is stored at a higher pressure than the confining pressure (Fokker, 1993).

2. Hydrogen can interact with sulfide, sulfate, carbonate, and oxide minerals that may be present in reservoirs or excavated caverns. At certain temperatures and pressures, chemical reactions could lead to production of toxic gases and the loss of hydrogen (Foh et al., 1979). If hydrogen is intended for membrane fuel cells or solid-state hydrogen storage, sulfur-based gases are especially harmful to these devices, as sulfur can poison them and decrease their efficiencies (Stone et al., 2009).

3. Hydrogen embrittlement, whereby metals meant to contain hydrogen become weakened, could be an issue if operating pressures and storage temperatures would increase above certain levels (Foh et al., 1979). However, the use of low-strength steels as well as plastic (e.g., PVC) materials obviates this problem (Melania et al., 2013).

4. In depleted oil/gas reservoirs, residual natural gas can affect hydrogen purity (Lord, 2009).

5. The mobility and viscosity differences between hydrogen and displaced fluid could lead to increased fingering and hydrogen losses (Carden and Paterson, 1979). A fingering pattern occurs when a more viscous material is displaced by a less viscous one (Homsy, 1987).

One of the main capital expenses of underground storage facilities is cushion gas, which must be present to provide a minimum operating pressure and is usually the same as the gas being stored ("working gas"). Cushion gas can consume up to 80% of the total gas capacity of the aquifer reservoir and 50% of the depleted gas/oil reservoir (Lord, 2009). Nitrogen[9] can be used as cushion gas as it is relatively inert to chemical reactions and it is considered cheap due to its abundance (Pfeiffer and Bauer, 2015). Carbon dioxide has also been proposed as a cushion gas, with the advantage that above 74 bar, it becomes supercritical and vastly decreases its volume, allowing more working gas to be stored (Oldenburg, 2003).

9. In salt caverns, nitrogen is sometimes also used as a blanket gas to protect the roof, but injection/withdrawal of the working gas is performed at greater depth to prevent mixing with the blanket gas.

This may allow more gas to be stored in the same volume. However, the use of a cushion gas different from the working gas can present separation challenges when the gas is withdrawn.

Synthetic Natural Gas

Synthetic natural gas (SNG) can be produced from fossil or biomass resources using thermochemical (as opposed to biological) conversion processes. If SNG is produced from fossil fuels, the net GHG emissions will be at least as high as ordinary natural gas, even if any excess CO_2 produced is captured and sequestered. An alternative, potentially lower-GHG route to SNG is to use CO_2 provided by other means (ideally captured from the atmosphere, or perhaps separated from biogas) along with hydrogen to produce methane thermochemically or electrochemically.

Making SNG from non-fossil inputs is generally more costly than making hydrogen, because of the additional step required for methanation (e.g., Benjaminsson et al., 2013).

An excellent overview of approaches for producing SNG can be found in Chandel and Williams (2009). For coal gasification, they found that the cost of producing SNG without CCS ranged from \$8.4 to \$9.5/MMBtu depending on the energy content of the coal. The coal cost was assumed to be ~\$1/MMBtu. With CCS added, the cost of SNG increased by ~\$1/MMBtu and ranged from \$9.2 to \$10.6/MMBtu. For biomass-based SNG, no CCS is required to keep GHG emissions low, but the higher cost of biomass plus additional capital hardware would drive the production cost of SNG to \$12/MMBtu with a biomass price of \$2.2/MMBtu.

Power-to-Gas

P2G is considered "one-way" electricity storage in that it can reduce electricity output when there is an excess, but other technologies must be used when generation is deficient, and P2G creates chemical fuels that must be utilized immediately or stored. P2G may be well-suited to excess renewable generation over multiple days, something that other types of electricity storage cannot do (storage capacities are limited due to cost, and in some cases, physical constraints of the storage medium).

The basic idea of P2G is to utilize electricity when it is plentiful (e.g., from daytime solar PV generation in excess of electricity demand) and convert it to chemical form—hydrogen or methane—for later use, similar to a battery. However, in addition to being able to re-convert the stored energy into electricity, unlike a battery the gas can be utilized directly in other applications. For a P2G plant producing methane (P2G-methane), the methane can be injected directly into the natural gas pipeline network. For a P2G plant producing hydrogen (P2G-hydrogen), the hydrogen can either be blended with natural gas and injected into the pipeline (subject to blending limits of ~10-20%), or utilized as pure hydrogen in fuel cell vehicles or other applications.

Power-to-gas hydrogen

P2G-hydrogen produces hydrogen from the electrolysis of water, with oxygen produced as a (usually discarded) byproduct. While commercial electrolysis systems exist, the technology is still maturing, with multiple approaches competing for future market share. The most common approaches that have been explored are alkaline, proton exchange membranes (PEM), and solid oxide electrolysis cells (SOEC) (Ferrero et al., 2016). Alkaline and PEM operate at temperatures of 40-90°C, whereas SOEC, which is not yet mature, operates at much higher temperatures (650-850°C) but offers higher efficiencies. Alkaline electrolysis is the most mature technology available with very different system size outputs, from 5 kW to 6 MW. The three largest P2G facilities are the RH2 WKA (1 MW) and Demonstration (2 MW) plants operated by EON, and the Solar Fuel Beta-Plant (6 MW), the world's largest P2G facility, operated by Audi (Gahleitner, 2013). PEM electrolysis is less mature than alkaline technology, with current plant capacities ranging from 1 to 56 kW (Gahleitner, 2013). As noted above, SOEC electrolysis is still at an early stage of development. However, SOEC systems ranging from as small as 1.5 kW and up to 220 kW can be found worldwide (Singhal, 2014). Current cost of hydrogen production ranges from €27 to €104/GJ (~$32 to $123/GJ) for grid injection, but are projected to drop to as little as €7/GJ (~$8/GJ) in 2030 (Ferrero et al., 2016).

Power-to-gas methane

P2G-methane is essentially a P2G-hydrogen plant with an additional methanation step whereby CO_2 (or sometimes CO) is combined with hydrogen to produce methane and water. Whereas water is inexpensive and readily available in most locations, obtaining CO_2 may be more difficult, as it is neither widely available nor cheap. About 33 million metric tons of CO_2 from naturally occurring underground sources in the Colorado Basin are used annually for enhanced oil recovery and food and chemical applications (Allis et al., 2001), but elsewhere, the most viable sources of CO_2 are either as a component of biogas (about 50% of anaerobic manure digestion and landfill gas is CO_2 by volume) (Götz et al., 2016), or via CO_2 capture from power plant or industrial facility flue gas (Boot-Handford et al., 2013). Direct CO_2 capture from air (Socolow et al., 2011; Lackner, 2013) or seawater (Willauer et al., 2014) is also a possibility. All these approaches are immature and, for air capture, inherently less efficient due to the low concentration of CO_2 in the atmosphere. Moreover, the net greenhouse gas (GHG) emissions of the CO_2 must be considered; of the options provided above, CO_2 from natural underground sources or captured from a fossil fuel-fired power plant would result in significant net GHG emissions, whereas CO_2 captured from biogas, biomass-fired power plants, or directly from the air or seawater would have net-zero GHG emissions. SCG (2014) has embraced P2G-methane and appears to favor using CO_2 from biogas.

Both Benjaminsson et al. (2013) and Götz et al. (2016) provide excellent reviews of available approaches for P2G-methane, which divide into catalytic and biological categories.

Catalytic approaches are all based on the Sabatier reaction, first discovered in the early 20th century. Temperatures of 200-550°C and pressures of 1-100 bar are typically needed, along with a metal catalyst (Ni, Ru, Rh or Co, though Ni is most often used). Because heat is produced in the reaction, it must be removed. Higher pressures are more favorable, as they allow higher conversion efficiencies as well as removal of high-grade heat that can be used for generating electricity, or heating a SOEC if used. A number of approaches, including fixed-bed, fluidized-bed, three-phase and structured reactors, have been explored.

Biological routes take place under much milder conditions, typically 20-70°C and 1-10 bar, and utilize a variety of microorganisms, including the crucial hydrogenotrophic methanogens that convert hydrogen and CO_2 into methane and water. Typically, a stirred tank is used because the organisms require an aqueous solution to grow, but hydrogen solubility is much lower than CO_2 in water. Also, optimal growth conditions for methanogens is 65°C, where solubilities of both hydrogen and CO_2 are much lower than at room temperature; as a result, pressurized reactors are preferable. Because of the much slower reaction rates of biological approaches, conversion of hydrogen into methane is limited to ~80% under best current conditions, with ~20% remaining in product gases. However, Götz et al. (2016) note that further improvements are possible. For instance, Bensmann et al. (2014) have explored injecting hydrogen directly into biogas digesters in order to convert the produced CO_2 into additional methane, without the need for initial separation.

Götz et al. (2016) conclude that P2G-methane, estimated to cost between €11 to €167/GJ (~$13 to $197/GJ), is not currently competitive with natural gas or even biomethane, but this situation could change as capital costs decline with maturing technology, higher natural gas prices, strong climate policy that effectively raises the price of natural gas, or very low off-peak electricity prices.

Vehicle Fuel Shifting and Electrification

This section discusses the main technology alternatives to fossil-fuel-based combustion in the transportation sector.

Electric vehicles

Light-duty electric vehicles are rapidly growing in California, thanks in part to the Governor's Zero Emission Vehicle (ZEV, 2014) Action Plan whose goal is 1.5 million vehicles on the road by 2025. Thus far, Californians own 230,000 ZEVs, or 47% of all ZEVs in the U.S. ZEVs include pure battery electric vehicles, plug-in hybrid electric vehicles, and hydrogen fuel cell vehicles (see *3.4.3.5 Hydrogen vehicles*); currently the majority of ZEVs are electric vehicles (IWG, 2016). California is also part of a broader multi-state effort with seven northeast states to deploy 3.3 million ZEVs by 2025 (ZEV Program Implementation Task Force, 2014).

According to PluginCars.com (2017), there are currently 15 battery electric vehicle models in the U.S. market, ranging from 62 to 315 miles per charge, and 20 plug-in hybrid electric vehicles ranging from 12 to 53 miles per charge. Costs have now fallen to general consumer levels, with 14 of the available models for $35,000 or less, including the much-anticipated Tesla Model 3 with an all-electric range of 200 miles.

Much of the expense of electric vehicles is the battery, which has fallen remarkably since 2010, when it was estimated to cost $1,000/kWh for a complete battery pack. In 2015, this cost had fallen to $270/kWh, and Tesla claims its 60 kWh Model 3 complete battery pack will cost less than $190/kWh, with reductions to $100/kWh forecast by 2020 (Lambert, 2017).

For a 2015 compact passenger vehicle, Brennan and Barder (2016) found that the average cost for an electric vehicle was $29,164 versus $17,146 for a conventional internal combustion engine vehicle. For a 2015 mid-size passenger vehicle, the electric vehicle cost was $37,865 versus $19,114 for an internal combustion engine vehicle. However, lower energy and maintenance costs, as well as current subsidies for electric vehicle purchases, make electric vehicle ownership more attractive.

Electrification of medium- and heavy-duty vehicles is also under way. In addition to prototypes or pilots by companies such as FedEx (2016), Daimler (Lockridge, 2016), Nikola Motor Company (Davies, 2016) and Tesla (Stewart, 2017a), California is providing funding assistance to expand manufacturing facilities and conduct technology demonstrations for buses, trucks, and other freight vehicles (IWG, 2016). California is also pursuing partial electrification of equipment used in marine ports (CARB, 2017b), rail electrification (e.g, McGreevy, 2017), and heavy-duty truck electrification in transportation corridors with high air pollution such as I-710 between Long Beach and Los Angeles (CALSTART, 2013).

Hydrogen vehicles

Hydrogen vehicles have long been a priority for California, starting with Executive Order S-07-04 promoting a hydrogen highway network in 2004 (CalEPA, 2005). The ZEV Action Plan (IWG, 2016) encourages the use of hydrogen fuel cell as well as electric vehicles, and California is committed to building a network of 100 hydrogen fueling stations throughout the State by 2024, through the requirements of AB 8 (CalEPA/CARB, 2016).

Fuel cells can operate at much higher efficiencies than conventional combustion engines, and after conversion of hydrogen into electricity, vehicles operate similarly to electric vehicles. The DOE is working to overcome technical barriers to fuel cell development that currently limit cost, performance, and durability. As platinum is a major cost component of fuel cells, research currently focuses on reducing the amount of platinum needed in a fuel cell, as well as finding alternative catalyst materials (www.energy.gov/eere/fuelcells/fuel-cells).

There are currently three models of light-duty fuel cell vehicles available on U.S. markets (www.fueleconomy.gov/feg/fcv_sbs.shtml), with two of the models only available in California and one also available in Hawaii. However, these vehicles currently cost around $60,000 or more (Edelstein, 2016; Goodwin, 2016; King, 2016), which is very high compared with conventional vehicles. As a result, further cost reductions will be necessary before fuel cell vehicles can become competitive with electric vehicles.

Larger fuel cell vehicles are also in development. UPS plans to launch the world's first hydrogen fuel cell delivery truck in 2018 (O'Dell, 2017), and Toyota recently unveiled a prototype hydrogen-powered heavy-duty semi-truck. While Toyota's truck has a fully loaded range of only 200 miles as opposed to 1,000 miles for a diesel-powered vehicle, it is aiming for a shorter-distance market such as the Long Beach-Los Angeles corridor (Stewart, 2017b).

According to Greene and Duleep (2013), if fuel cell vehicles were manufactured at significant scale (200,000/year), the total vehicle cost would be $37,000 in 2016 and $33,200 in 2020, without any technology breakthroughs.

Natural gas vehicles

In the transportation sector, the majority of GHGs come from diesel-fueled vehicles. This is why policymakers in California are raising costs for diesel fleet operators through some existing and forthcoming regulations. According to comments from Southern California Gas Company (Rasberry, 2015), instead of paying these higher costs, heavy-duty vehicles could be converted from diesel to natural gas or even biogas, without harming California's economy. This conversion would lower GHGs, reduce nitrogen oxide and particulate matter emissions, and also help save money to vehicle owners.

Natural gas is available as Compressed Natural Gas (CNG) or Liquefied Natural Gas (LNG). The advantage of CNG over LNG is that it is produced locally, has a lower fuel cost, and does not evaporate if not used. The LNG process is more complex, as LNG has to be stored in special tanks, requires special refueling equipment, and needs to be used within a certain time to avoid tank venting (Agility, 2017). CNG is less dense than LNG, with a density of 215 kg/m^3 at 250 bar (Unitrove, 2017), as compared to ~450 kg/m^3 for LNG (GIIGNL, no date). As a result, LNG vehicles with the same tank volume have a greater driving range than CNG vehicles (Go With Natural Gas, 2014).

There are about 165,000 NGVs in the U.S. today (NGVAmerica, 2015) and 24,600 in California (Schroeder, 2015). Most of these are heavy-duty vehicles; only ~7,000 light-duty NGVs were available in the U.S. in 2014 (Davis et al., 2016). Of these light-duty NGVs, ~7% used LNG, with the remainder using CNG. There are more than 330 CNG refueling stations in Southern California, and more than 1,500 across the U.S. (Rasberry, 2015).

Sustained low prices for natural gas coupled with higher and more volatile gasoline and diesel prices have accelerated market adoption of natural gas vehicles, particularly in heavy-duty markets (Schroeder, 2015). According to DOE (2017), the recent average national retail CNG cost was $2.43 per gallon diesel equivalent (GDE), cheaper than either diesel or gasoline. For LNG, the cost was slightly higher at $2.52/GDE, nearly the same as that of diesel ($2.55/GDE).

In the U.S., in 2013, the retail price of a Honda Civic that was designed and built to run on natural gas was $23,300, versus a gasoline-fueled Honda Civic at $18,000. The Ford F250 pickup truck that was designed to run on gasoline but converted after-market to natural gas cost $43,500, versus $34,000 for the gasoline version (Yip, 2014).

Building Electrification

While research on building electrification is more nascent, the Sacramento Municipal Utilities District (SMUD) published a ground-breaking report in 2012 concluding that a large subset of residential and commercial building end uses in California could be electrified with payback periods of 10 years or less (ICF International, 2012). In the residential sector, these technologies were heat-pump-based water heating (10 years), space heating (7 years) and pool heating (1 year), and various electric cooking technologies (1 year). In the commercial sector, the technologies were ground-source heat pump-based space heating (6-8 years), and solar water heating with electric backup (2-4 years). The report concluded that "heat pump heating and heat pump water heating should be prioritized for electrification programs because these technologies are cost effective, do not have significant technical or societal barriers, and have significant GHG emission reduction potential" (ICF International, 2012, p. ii). While these conclusions are specific to the SMUD regional climate, they may be applicable to other regions of California as well. A recent report by Raghavan et al. (2017) concluded that residential electric heat pump water heaters were feasible in California, with significant GHG benefits.

Appendix 3-3: Recent Federal and State Policies

Federal Policies Relevance to Natural Gas Use and Storage

About half of the country's 415 UGS facilities fall under FERC authority; the rest are regulated by state entities (Interagency Task Force, 2016). Therefore, both state and federal policies could be important to the future of UGS in California.

FERC Policy on Storage Development

FERC's long-held general policy, demonstrated in multiple orders, is that more storage, whether new or expansion of existing, is better. What this means for California is that if there is a new interstate storage project that might be constructed in California, or if there is new interstate storage planned in other adjacent states that could substitute for new

UGS in California (connected to CA markets via pipelines), FERC would do everything in its jurisdictional authority to ensure such proposals would be considered, approved as appropriate, and placed into service.

As noted in FERC Order No. 678 (FERC, 2006), FERC clearly pointed out that there are "efforts already underway at the Commission to adopt policy reforms that would encourage the development of new natural gas storage facilities while continuing to protect consumers from the exercise of market power." Further, in Order No. 678, FERC notes that it "is amending its regulatory policies in the Final Rule in order to facilitate the development of new natural gas storage capacity to ensure that adequate storage capacity will be available to meet anticipated market demand and to mitigate natural gas price volatility."

In light of the CPUC's consideration of eliminating Aliso Canyon as a UGS provider in California, FERC jurisdictional storage facilities could play a key role in providing much-needed UGS as a bridge to a future based on renewables.

PHMSA Interim Final Rule

On December 14, 2016, the U.S. Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) issued an Interim Final Rule that revises pipeline safety regulations. The Final Rule specifically addressed safety issues related to UGS by including regulations on well integrity, wellbore tubing, and casing. More information is available about this Final Rule in Chapter 2, *How will new integrity and safety rules affect natural gas reliability?*

As a response to the Aliso Canyon incident and public concern, Section 12 of the Protecting Our Infrastructure of Pipelines and Enhancing Safety (PIPES) Act charged PHMSA to develop a minimum federal safety standard for all UGS (PHMSA, 2016). The Final Rule incorporates two Recommended Practices from the American Petroleum Institute, API RP 1170 and 1171. The first concerns "Design and Operation of Solution-mined Salt Caverns used for Natural Gas Storage" and the second addresses "Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs." Both create safety standards for risk management and require reporting of significant incidents (PHMSA, 2016). However, PHMSA announced on June 20, 2017, that it would not be enforcing parts of their newly written regulations on natural gas storage facilities while they consider a petition to change the rules (PHMSA, 2017).

California Energy System Goals Policies Relevant to Natural Gas Use and Storage

Statewide GHG targets and cap-and-trade programs

Executive Order S-3-05: 2050 GHG target (80% below 1990 level)

On June 1st 2005, Governor Arnold Schwarzenegger released Executive Order S-3-05 which created a new target for greenhouse gas emissions. According to the document, by 2020, GHG emissions should be reduced to 1990 levels, and by 2050 they should be reduced to 80% below 1990 levels (Office of Governor Edmond G. Brown Jr., 2005). In addition, this executive order creates the Climate Action Team and appoints the Secretary of Cal/EPA to coordinate plans for meeting these targets with the help of other State agencies.

AB 32 (Pavley, 2006): 2020 GHG target (100% of 1990 level) and cap & trade policy

The Global Warming Solutions Act of 2006 (AB 32) codifies part of Executive Order S-3-05, requiring California to reduce its GHG emissions to 1990 levels by 2020. The bill gives the Air Resources Board (ARB) the authority to develop regulations that would help achieve this goal (CALI, 2006a). Apart from using a regulatory approach, ARB has also used a market approach through cap and trade. Cap and trade is a program that puts a limit on the amount of GHG emissions and enforces this limit by placing penalties on companies that exceed it. If companies opt to release more GHG, then they are able to buy and trade allowances through an auction system (CARB/CalEPA, 2014).

SB 32 (Pavley, 2016) and AB 197 (E. Garcia, 2016): 2030 GHG target (40% below 1990 level)

SB 32 set a new target for the ARB. This bill requires the board to reduce GHG emissions to 40% below the 1990 level by 2030 (CALI, 2016b). The bill was paired with AB 197, which gives the Legislature oversight over ARB when adopting regulations. This bill does not authorize the extension for ARB to utilize cap and trade, but it does provide the mechanisms that are needed to reach the goals in SB 32 (Office of Governor Edmund G. Brown Jr., 2015a).

SB 32 codified Executive Order B-30-15 issued by Governor Brown in April 2015.

AB 398 (E. Garcia, 2017): Cap and trade extension to 2030

On July 25, 2017, AB 398 was approved by Governor Brown, giving the ARB the explicit authority to establish and utilize a cap and trade program through 2030. The bill also requires ARB to update their scoping plan by January 2018. In relation to storage, AB 398 provides tax exemptions for buildings and foundations used for the generation, production, or storage of electric power. It also gives tax exemptions for those who purchase property or equipment for the use of generation, production, or storage and distribution of electric power (CALI, 2017b).

AB 617 (C. Garcia, 2017): Nonvehicular air pollution: criteria air pollutants and toxic air contaminants

As part of the cap and trade package, AB 617 was approved by the Governor on July 26, 2017. The bill addresses air quality standards as it pertains to the California cap and trade program. The purpose of the bill is to systemize a standard reporting system for air pollutants and Toxic Air Contaminants. It creates a system for implementing control technology for pollutants and increases penalties for certain types of pollutants (CALI, 2017c).

California Energy System Means Policies Relevant to Natural Gas Use and Storage

Underground gas storage

State of California RFP on Eliminating Aliso Canyon Storage Facility

On June 16, 2017, the California Public Utilities Commission (CPUC) issued notice that it is requesting public comment on the Aliso Canyon Reliability and Economic Analyses draft pre-solicitation on a plan to study the potential for eliminating the Aliso Canyon UGS facility (CPUC, 2017a). One key matter in the request for proposal (RFP) concerns estimating the impact of the reduction or elimination of the ability to use the Aliso Canyon UGS facility to store gas bought in the off-season for winter use and avoid or reduce spot market purchases on peak days. This issue is discussed in detail in Chapter 2.

Specifically, the CPUC asks “should the commission reduce or eliminate the use of the Aliso Canyon storage facility, and if so, under what conditions and parameters, and in what time frame?”

The CPUC did not receive any proposals for their original RFP. A second RFP was issued on September 11, 2017 with proposals due on October 16, 2017. (DGS, 2017).

Letter from Chair Weisenmiller

In response to the RFP, the Chair of the California Energy Commission (CEC), Robert Weisenmiller, released a letter to the President of the CPUC on July 19, 2017. Chair Weisenmiller addressed his concerns about California’s dependency on fossil fuels and what that means for California’s climate goals. Chair Weisenmiller urged the CPUC to plan for the permanent closure of Aliso Canyon. He stated that his “staff is prepared to work with the CPUC and other agencies on a plan to phase out the use of the Aliso Canyon natural gas storage facility within ten years” (CEC, 2017a).

In addition, Chair Weisenmiller specifically addresses this report in relation to the Governor’s 2016 emergency proclamation. He acknowledges that a study on the long-term viability of all natural gas storage facilities in California is being conducted by CCST, and this report "will inform how the state will rethink all natural gas storage facilities in California" (CEC, 2017a).

Electricity generation

SB X1-2 (Simitian, 2011): Prior renewable portfolio standard targets 33% by 2020

The California Energy Commission reviews the amount of renewable energy capacity being installed in California and updates the legislature on the progress being made toward the state's renewable energy goals. These goals are referred to as the State's renewable portfolio standard (RPS) targets (CEC, *Renewables Portfolio Standard*). The RPS goal was originally set in 2002 as a 20% requirement by 2017. In April 2011, Governor Brown signed Senate Bill X1-2 to approve a new target for renewables set at 33% by 2020 (CALI, 2011).

SB 350 (De Leon, 2015): 50% RPS in 2030

In October 2015, Governor Brown signed Senate Bill 350 to put into law a requirement to serve 50% of California's electricity use with renewable energy resources by 2030. This increased the RPS from 33% by 2020 to 50% by 2030 (CALI, 2015).

SB 100 (De Leon, 2017): California Renewables Portfolio Standard Program: Emissions of greenhouse gases

If passed, this bill creates a 100% zero-carbon resource electricity generation portfolio target. It would increase the current 2030 target from 50% to 60%, and increase that target to 100% by 2045 (CALI, 2017a). Note that the term "zero-carbon resource" would include generation technologies other than renewable electricity, such as nuclear power.

AB 2514 (Skinner, 2010): Energy storage systems

AB 2514 was passed and signed into law by Governor Brown in September 2010. The bill gives the CPUC the authority to set targets for load serving entities to obtain energy storage systems. The targets deemed appropriate by the CPUC would have to be adopted by 2015 and 2020. In addition, publicly owned utility companies are required to set their own energy storage targets and see that those targets are reached by 2016 and 2021 (CALI, 2010). In October 2013, in response to AB 2514, the CPUC established energy storage goals for utilities. In D. 10-03-040, the CPUC established a target of 1,325 megawatts of energy storage by 2020. This target applied to three investor-owned utility companies—PG&E, Edison, and SDG&E. Each company is required to install energy storage capacity by no later than the end of 2024 (CPUC, 2017b). However, the goal did not specify the required number of hours of storage (or, equivalently, the energy capacity in MWh), which is necessary to determine how much storage capacity is actually needed. For example, assuming eight hours of storage are required, the goal would imply 10,600 MWh of storage capacity would be built. If only one hour of storage on average is required, this capacity would be much lower (1,325 MWh).

SB 1368 (Perata, 2006): Imported coal phase-out

This bill began the process of phasing out coal production in California by establishing the emissions performance standard which applies to baseload generation owned by or under long-term contract to a utility that serves California (CALI, 2006b). As a result, 3,463 MW of coal-fired electric generation capacity was removed from California between 2006 and 2016 (CEC, 2016a). The CEC projects that coal fired generation will serve less than 3 percent of California's electricity consumption by 2024 and is expected to reach zero consumption by 2026.

Once-through cooling phase-out

In October 2010, a once-through-cooling policy was adopted by the State Water Resources Control Board (SWRCB) as a response to the Clean Water Act. This policy was created as a method of improving water quality goals while also ensuring electricity grid reliability. The SWRCB worked closely with the CEC, CPUC, and CAISO to develop a policy that specifically required 19 of California's power plants to switch to closed-cycle evaporative cooling, because it was the best available technology at the time (CEC, 2017b). Closed-cycle evaporation cooling refers to a system that transfers waste heat to the surrounding air through water evaporation instead of transferring that waste to surrounding oceans, rivers, and lakes. Each plant has the option of either reducing their intake flow rate to a level that can be attained by this technology or using operational or structural controls to reduce "impingement mortality and entrainment" for the facility as a whole to 90% of option 1. If neither option worked, the plant has the option of shutting down. Between 2010 and 2029, all California power plants are scheduled to comply. Most have plans to retire, while others have plans to repower (CEC, 2017b).

Nuclear phase-outs: San Onofre Nuclear Generating Station (SONGS) and Diablo Canyon Nuclear Power Plant

There are two nuclear power plants in California that have once-through-cooling (OTC) technologies, SONGS and Diablo Canyon. The two plants made up 55% of all OTC water use. In January 2012, SONGS was shut down because the stream generator had tube leaks (CEC, 2017b). Due to the cost of repairs, Southern California Edison announced the permanent retirement of SONGS in June 2013. In August 2016, PG&E announced to the CPUC that they would be retiring Diablo Canyon by 2025. PG&E worked with numerous groups including labor, environmental, and community advocacy organizations to develop this proposal to shut down its plant (CEC, 2017b). The phasing out of these two facilities indicates a move towards nuclear power phase-outs in California.

SB 338: Integrated resource plan: peak demand.

Currently, the California Public Utilities Commission (CPUC) must adopt a process for each load-serving entity to file an integrated resource plan and a schedule for periodic updates to the plan to ensure that the load-serving entity meets California's greenhouse gas emission reduction targets and the requirement to procure at least 50% of its electricity from eligible renewable resources by December 31, 2030. SB 338 (CALI, 2017f) requires the CPUC and the governing boards of local publicly owned electric utilities to consider, as part of the integrated resource plan process, the role of distributed energy (DE) resources and other specified energy- and energy-related tools. This will help to ensure that each load-serving entity or local publicly owned electric utility, as applicable, meets energy and reliability needs, while reducing the need for new electricity generation and new transmission in achieving the State's energy goals at the least cost to ratepayers.

Fuels

Low-carbon fuel standard (LCFS)

The LCFS was created in 2007 by Governor Schwarzenegger's Executive Order S-01-07. The Executive Order establishes a statewide goal to reduce carbon emissions from California transportation fuels by 10% by 2020 (Office of Governor Edmund G. Brown Jr., 2007). The transportation industry is responsible for 40% of GHG emissions. The authority was given to the ARB to determine whether a LCFS could be adopted as a means of reaching the emissions goals set by AB 32. The order allows ARB to use a market-based approach to regulate GHG emissions from the transportation industry. The LCFS requires producers of petroleum-based fuels to reduce the carbon emissions of their products either through technological improvements or by purchasing LCFS credits from companies that sell low carbon alternative fuels like biofuels, electricity, natural gas, or hydrogen (CEC, 2017c). The goal of the program is to reduce dependency on petroleum and reduce the emissions of other air pollutants.

Governor Brown's 2015 State of the State Address: Reduce today's petroleum use in cars and trucks by up to 50 percent

In Governor Brown's 2015 State of the State Address, he stated his commitment to reducing petroleum use in cars and trucks by up to 50% by 2030 although no legislation has been passed to accomplish this goal (Office of Governor Edmund G. Brown Jr., 2015b).

Executive Order S-06-06, Imported biofuels: 75% in-state production

In April 2006, Governor Schwarzenegger released Executive Order S-06-06 that sets California targets to increase the use of bioenergy (Office of Governor Edmund G. Brown Jr., 2006). The order requires State agencies to work together to increase the use of biofuels to 40% by 2020 and 75% by 2050. Furthermore, in a study conducted by CCST in 2013 entitled *California's Energy Future-The Potential for Biofuels*, one of the conclusions reached by the study is that in-state biomass is not sufficient to reach liquid fuel and gaseous fuel demand in 2050 and therefore would be supplied by imported biofuels. Imported biofuels from out of State or country would allow for a cheaper alternative to meet the State's GHG reduction goals (CCST, 2013).

AB 1900 (Gatto, 2012) on biomethane

AB 1900 required the CPUC to identify components of landfill gas and develop testing procedures for biomethane that is injected into common carrier pipelines. Specifically, this bill called upon the CPUC to adopt standards for biomethane that is to be injected into common carrier pipelines (CALI, 2012). This standard was put in place to ensure the gas meets pipeline safety and integrity requirements. In response to the bill, the CPUC released decision 14-01-034 in January 2014. The decision outlines the 17 compounds of concern found in biomethane and establishes concentration standards for each element before it could be injected into the utilities' gas pipeline system (CPUC, 2014).

SB 433 (Mendoza, 2017): Gas corporations: zero-carbon and low carbon hydrogen

SB 433 would give the Public Utilities Commission (PUC) the authority to allow gas corporations to obtain zero-carbon hydrogen or low-carbon hydrogen to serve consumers (CALI, 2017d). This bill would authorize gas corporations to recover in rates the reasonable cost of pipeline infrastructure developed to deliver and transport the zero-carbon or low carbon hydrogen (CALI, 2017d). Furthermore, SB 433 would give the State Air Resources Board, the CPUC, and the State Energy Resources Conservation and Development Commission the authority to approve the production of zero-carbon or low-carbon hydrogen for its intended purposes (CALI, 2017d). SB 433 did not pass through the Assembly Committee on Utilities and Energy, but may be re-introduced during the next legislative cycle.

Vehicle efficiency and electrification

AB 1493 (Pavley, 2002): standards for light-duty vehicles

AB1493 requires the ARB to develop and adopt regulations to achieve cost effective reductions in GHG emissions from passenger, light-duty, and other noncommercial vehicles (CARB/CalEPA, 2007). The bill took effect in 2006 and applied to vehicles manufactured from 2009 to 2016. ARB originally approved regulations required by the bill in 2004, however, these regulations received push back from the automaker industry (CARB/CalEPA, 2017b). An agreement was reached in May 2009 that allows for compliance flexibility from manufacturers. The original regulations added four new contaminants to the criteria for toxic air contaminant emission from vehicles- carbon dioxide, methane, nitrous oxide, and hydrofluorocarbons. The ARB estimates that the motor vehicle greenhouse gas emissions standards will reduce GHG emissions by approximately 30 million metric tons in 2020 and 50 million metric tons in 2030. This constitutes an 18% reduction in emissions from passenger cars 2020 and a 27% reduction in 2030 (CARB/CalEPA, 2007).

Zero Emission Vehicles (ZEV) Action Plan

In Governor Brown's Executive Order B-16-12, the Governor orders the State government to support and assist the accelerated commercialization of ZEVs. The Executive Order sets a target for 1.5 million ZEVs on the roads by 2025. It gives State agencies the task of building the infrastructure for these vehicles and encouraging the growth of ZEVs within the manufacturing and private sectors as well (Office of Governor Edmund G. Brown Jr., 2012). The 2016 Action Plan (IWG, 2016) highlights the progress made by agencies to implement ZEVs within the State market and also outlines the future steps agencies will take in order to achieve the goals set by the Governor's Executive Order. In the summer of 2016 there were more than 230,000 ZEVs on the road in California. Moving forward, State agencies plan on raising consumer awareness and education about ZEVs, focusing on building infrastructure to improve ZEV accessibility, broadening ZEV technology in order to reach consumers who are interested in larger vehicles, and aiding ZEV expansion beyond California (Office of Governor Edmund G. Brown Jr., 2016).

Medium and heavy-duty GHG emissions

In October 2016, the ARB collaborated with the U.S. Environmental Protection Agency (U.S. EPA) and National Highway Traffic Safety Administration (NHTSA) to develop federal Phase 2 standards for GHG emissions for medium and heavy duty vehicles. While Phase 1 focused on manufacturing improvements in engine and vehicle efficiency, Phase 2 would establish technology that could allow for the creation of standards for engines and vehicles (CARB/CalEPA, 2017c). These standards would continue to increase GHG reduction goals from Phase 1 standards. ARB plans to propose California Phase 2 implementation in late 2017 (CARB/CalEPA, 2017c).

AB 8 (Perea, 2013) and Executive Order S-07-04 promoting a hydrogen highway network

In April 2004, Governor Schwarzenegger released Executive Order S-07-04, which established the California Hydrogen Highway Network (CaH2Net). The purpose of the Executive Order was to ensure the infrastructure for hydrogen vehicles was in place to support the growing number of hydrogen vehicles on the road. The California EPA developed a Blueprint Plan outlining the steps needed in order to implement the CaH2Net (CARB/CalEPA, 2016a). The plan set the foundation for California's hydrogen achievements and allowed for both industry and government coordination for policy development. With the passage of AB 8 (CALI, 2013), California's ability to implement a hydrogen fuel station network was accelerated. AB 8 dedicates up to $20 million per year to developing the infrastructure needed for hydrogen fueling stations (CARB/CalEPA, 2016a). This initiative is funded through the Alternative and Renewable Fuel and Vehicle Technology Program (ARFVTP). This will enable more fuel cell electric vehicles (FCEVs) and zero emission vehicles (ZEVs) to play a larger role in meeting California's emission reduction goals.

Advanced Clean Transit initiative and Innovative Clean Transit measure

The Advanced Clean Transit initiative is a measure proposed by the California Air Resources Board that would incentivize transit fleets to switch to more fuel-efficient technologies (CARB/CalEPA, 2016b). The initiative would allow for transit companies to slowly integrate advanced technologies within their existing operations creating space for renewable fuels or advanced technologies to help reduce emissions. The types of advanced technologies available vary from zero emission battery electric and fuel cell electric buses to hybrid buses and clean combustion engines. As of June 2016, there were 88 zero-emission battery electric and fuel cell electric buses operating in California, and 162 more were on order. The Advanced Clean Transit measure has been expanded to include such things as near-term operations of zero-emission buses and renamed as the Innovative Clean Transit measure (CARB/CalEPA, 2017a).

California Sustainable Freight Action Plan

Evolving from Executive Order B-32-15, California released the *California Sustainable Freight Action Plan* in 2016. The plan was a joint effort by the California State Transportation Agency, California Environmental Protection Agency, Natural Resources Agency, California Air Resources Board, California Department of Transportation, California Energy Commission, and Governor's Office of Business and Economic Development. It provides a long-term vision of California's transition to a more efficient, more economically competitive, and less polluting freight transport system. It includes near-term strategies and targets for 2030 and 2050.

Near-term guiding principles include three pilot projects (Dairy Biomethane for Freight Vehicles, Advanced Technology for Truck Corridors, Advanced Technology Corridors at Border Ports of Entry) and steps for progress towards the Plan's vision. Targets for 2030 include: improving freight system efficiency by 25%, deploying over 100,000 freight vehicles and equipment capable of zero-emission operation, maximizing near-zero emission freight vehicles and equipment powered by renewable energy, and increasing state competitiveness and fostering future economic growth within the freight and goods movement industry.

Overall, State agencies recognize potential contributions from several measures: (1) Development and use of nonpetroleum-based transportation fuels such as diesel and gasoline substitutes, biomethane, renewable hydrogen, and renewable electricity; (2) Injection of biomethane into natural gas pipelines; (3) New technologies to increase vehicle efficiency; (4) Research, demonstration, and deployment of fuel cell electric and hybrid vehicles; (5) Continued investment in next-generation engines; (6) Integration of advanced energy storage technologies with transportation electrification; (7) Information technology management systems; (8) Enhanced traffic management technology; (9) Utilization of additional renewable electricity generation for fueling ZEVs and equipment in the freight sector; and (10) Developing a natural gas vehicle research roadmap to identify opportunities for integrating low-carbon renewable natural gas into California's medium-and heavy-duty fleets.

California Mobile Source Strategy

California's *Mobile Source Strategy* (ARB, 2016) demonstrates how the State can simultaneously meet air quality standards, achieve GHG emission reduction targets, decrease health risk from transportation emissions, and reduce petroleum consumption by 50%, all by 2030. ARB estimates that these actions would have a negligible impact on the California economy, with Gross State Product slowing by 0.051%/yr between 2023 and 2031.

The actions in the report support numerous efforts at the state level, including: (1) Modernizing and upgrading transportation infrastructure; (2) Deploying cleaner vehicle technologies; (3) Increasing engine performance standards and fuel efficiency; (4) Incentivizing funding to achieve further ZEV deployment; (5) Increasing renewable electricity generation to 50%; (6) Increasing use of renewable fuels (renewable diesel from biomass, NO_x-mitigated biodiesel, renewable natural gas from biomethane, gas to liquid diesel from biomethane, renewable hydrocarbon diesel, and/or co-processed renewable hydrocarbon diesel); (7) Reducing growth in vehicle miles traveled; and (8) Increasing worksite efficiencies. More precisely, the number of plug-in hybrid electric and noncombustion zero-emission passenger vehicles, including battery-electric and hydrogen fuel cell vehicles, would increase by over 50% compared to current programs. Internal combustion engine technology for heavy-duty vehicles would also be 90% cleaner than today's standards, with renewable fuels comprising 50% of fuels burned.

Building efficiency and electrification

IOU efficiency goals

In a 2004 decision, (D.) 04-09-060, the California Energy Commission set energy efficiency goals for investor-owned utilities (IOUs) programs (CPUC, 2004). These goals are referred to as the Energy Action Plan. There are four main objectives for the Energy Action Plan. The first is to provide guidance for the IOU programs next energy efficiency portfolios. This means that based on the outline provided for developing an energy efficiency goal, the CPUC is able to use this decision as a baseline for adopting annual and ten-year goals for electric and natural gas savings (CPUC, 2013). This also allows the utilities to create their own portfolios, which are measured and evaluated by the Energy Division. The second objective of the decision is to update the forecast for energy procurement planning by integrating the IOUs' energy efficiency goals. The third is to help inform California's future GHG reduction targets. The fourth, and last, is to have the Energy Action Plan set benchmarks for shareholder incentives (CPUC, 2013).

Title 24 standards

The California Building Standards Code, also known as Title 24, is a California Code of Regulations that sets standards for constructing buildings in California. It is comprised of twelve parts that sets regulations on all different aspects of building, including mechanics, plumbing, electric, and energy codes (DOE, 2017). The main purpose of each code is to ensure safety standards in order to safeguard building occupants. Within part 6 of the Energy Code, there are efficiency standards that newly constructed buildings, additions, alterations, and repairs are subject to. This means that there is a limit to how much energy a building can consume under the restrictions of Title 24 (DOE, 2017). In 2004, Governor Schwarzenegger signed Executive Order S-20-04, also referred to as the Green Building Initiative. This Executive Order set regulations in place that would improve energy efficiency within nonresidential buildings. The goal was to decrease the energy use of nonresidential buildings by 20% in 2015. In addition, in 2010 the California Green Building Standards Code was added to Title 24. This code requires that new buildings reduce water consumption, increase system efficiencies, divert construction waste from landfills, and install materials that would decrease the amount of pollutants emitted into the atmosphere (DGS, 2010). The purpose is for the code to help achieve GHG emission reduction goals by 2020 and possibly beyond. Title 24 standards are currently updated every three years.

California appliance efficiency standards

The Appliance Efficiency Regulations, also known as Title 20, are regulations that set standards for energy consumption for both federally and non-federally regulated appliances (DOE, *Appliance Efficiency Regulations*). Title 20 was established in 1976 in response to the Warren-Alquist Act, which charged the CEC to develop efficiency standards to reduce California's energy consumption (DOE, 2017). They are updated periodically based on new technologies and efficiency methods.

SB 350: Doubled building efficiency in 2030

SB 350 (De Leon, Chapter 547, Statutes of 2015) requires the CEC to establish statewide energy efficiency targets that will double energy efficiency savings in electricity and natural gas final end uses by 2030 (CALI, 2015). The CEC will do so to the extent that it is cost effective, feasible, and does not negatively impact public health and safety. The CEC has held multiple workshops to discuss the best approach to doubling energy efficiency targets. They held workshops in January 2017 and plan to publish a draft of their analysis in late summer of 2017 (CEC, *Doubling Energy Efficiency Savings*). As per SB 350, the CEC is scheduled to establish their targets by November 1, 2017.

Zero net energy buildings policy: residential (2020) and commercial (2030)

In SB 1389 (Bowen and Sher, Chapter 568, Statutes of 2002), the CPUC was charged with developing energy policies that promote energy reliability while also conserving resources, conserving the environment, enhancing the economy, and protecting public health and safety (CALI, 2002). In response, the CPUC established the Integrated Energy Policy Report, which is updated every two years to reflect changing energy technologies. The goal that the CPUC set is for all new residential buildings in California to produce zero net energy by 2020 (CPUC/CEC, 2015) and for all new commercial construction to produce zero net energy by 2030 (CEC, 2007). The CPUC worked closely with the State's IOUs in order to develop an Action Plan to achieve their goals. The 2019 building energy efficiency standards (Title 24) pre-rulemaking is in active discussion at the CEC and among public stakeholders as of the time of this writing (Summer 2017). Title 24 compliance can be met for both mixed-fuel (electricity and natural gas) and all-electric homes.

The current proposed approach for mixed-fuel homes is to maximize cost-effective building envelope efficiency, and to establish a minimum rating for energy efficiency in each climate zone that can only be met with efficiency measures (thus, there is no provision for increased solar PV to substitute for a lower level of efficiency) (Shirakh, M., C. Meyer, B. Pennington, 2017). The PV system will be sized prescriptively to displace the annual site electricity use (in kWh) of the mixed-fuel home. There is currently no requirement for low-carbon gas (e.g., biomethane) or a larger-sized PV system to offset the site-level natural gas fuel consumption in a mixed-fuel home.

For all-electric homes, minimum building shell energy efficiency measures would be similar to those for mixed-fuel homes, and the current proposal is for the PV system to be sized to that of a mixed-fuel home of equivalent area (Shirakh, M., C. Meyer, B. Pennington, 2017). Requiring a larger PV system is currently not preferred, because it could discourage all-electric home construction and also exacerbate issues with California's net load.

AB 758

According to Assembly Bill 758 (Skinner, Chapter 470, Statues 2009), the CEC and CPUC must work together to address the best methods to improve energy efficiency within existing residential and nonresidential buildings (CALI, 2009). In 2016, the CEC released a new Existing Building Energy Efficiency Action Plan, which incorporates the goals set by Senate Bill 350 to double energy efficiency savings. The plan includes programs that would use market mechanisms to change existing commercial, residential, and public buildings to more energy efficient buildings (CEC, 2016b).

Other policies

SB 1383 (Lara, 2016): Short-lived climate pollutants (SLCPs)

SB 1383 directs the ARB to approve and implement a plan to reduce emissions for short-lived climate pollutants (SLCPs) by 2030 (CALI, 2016c). SLCPs are different from long-lived pollutants like carbon dioxide not just because they stay in the atmosphere for a shorter period of time, but because they have the potential to heat the atmosphere in greater measures compared to long-term pollutants (CARB/CalEPA, 2017d). Short-lived pollutants include methane, hydrofluorocarbons, and black carbon. SB 1383 requires a 40% reduction in methane and hydrofluorocarbon gases by 2030 and 50% reduction in black carbon by 2030. In addition, it establishes procedures to reduce SLCP emissions from dairy and landfill sources (CALI, 2016c). ARB's SLCP Reduction Strategy was approved in March 2017.

AB 726 (Holden, 2017): Energy

AB 726 would authorize the transformation of the California ISO into a regional organization if the ISO governing board undertakes certain steps and the Commission on Regional Grid Transformation, created by the bill, makes specified findings by December 31, 2018. The bill would make inoperative other provisions of existing law relating to the ISO entering into a multistate entity or transforming into a regional organization unless the Commission on Regional Grid Transformation does not make the specified findings by that date. (CALI, 2017e). AB 726 did not pass through the Senate Rules Committee, but may be re-introduced during the next legislative cycle.

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Appendix 3-4: Scenario Feasibility Assessment

In this section, we review costs, scale-up rates, technical resource limits, and technological maturities of three of the four California scenarios discussed in 3.3. Demand for UGS in 2050, using data from E3 (2015a). This is important for understanding the relative viability of scenarios that the State could pursue, and therefore its impacts on UGS investment. However, it must be pointed out that the data used for the cost assessments are likely now out of date, as the cost of both renewables and natural gas have fallen, though gas prices could as well increase in the future.

Costs

In addition to the cost information contained in Appendix 3-2: Energy Technologies, E3 (2015a) provided some overall scenario implementation cost estimates relative to a baseline scenario that does not meet the GHG targets. The three scenarios presented here are "CCS," which is similar to our Scenario A (fossil-CCS + building electrification), "Straight Line," which is similar to our Scenario C (intermittent renewables + building electrification), and "Low Carbon Gas," which is similar to our Scenario D (intermittent renewables + low-carbon gas). E3 had no scenario similar to our Scenario B (flexible, non-fossil generation + building electrification), though many other studies have such scenarios.

E3 estimated annual costs relative to a reference baseline for implementing each scenario. Uncertainty analysis was included in their calculations (±50% in gasoline, diesel and natural gas prices, and reduction in key technology costs in the low fuel price case), which produced significant ranges on the estimates. E3 found that, in both 2030 and 2050, the CCS scenario was lower cost and the Low-Carbon Gas scenario, higher cost, than the Straight Line scenario, though uncertainty ranges among the three scenarios overlapped considerably. Costs are plotted on the vertical axis against GHG reduction (relative to the 1990 level) on the horizontal axis. See Figure 13 and Figure 14.

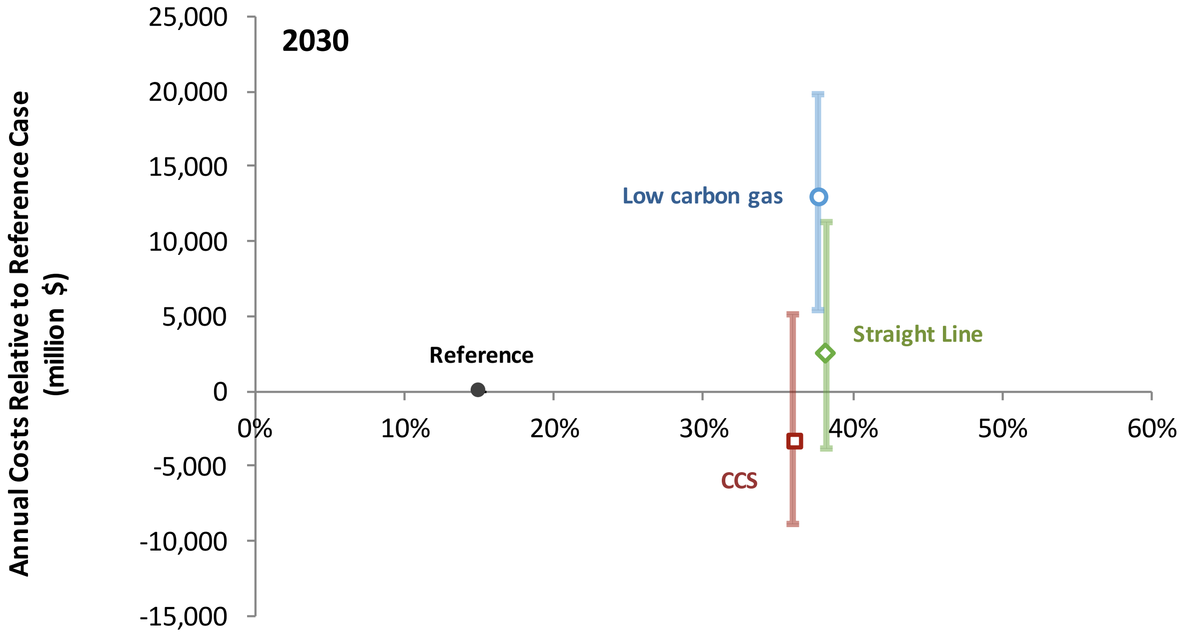


Figure 13. Scenario cost estimates for 2030. Costs are plotted on the vertical axis against GHG reduction (relative to the 1990 level) on the horizontal axis. CCS = Scenario A; Straight Line = Scenario C; Low carbon gas = Scenario D.

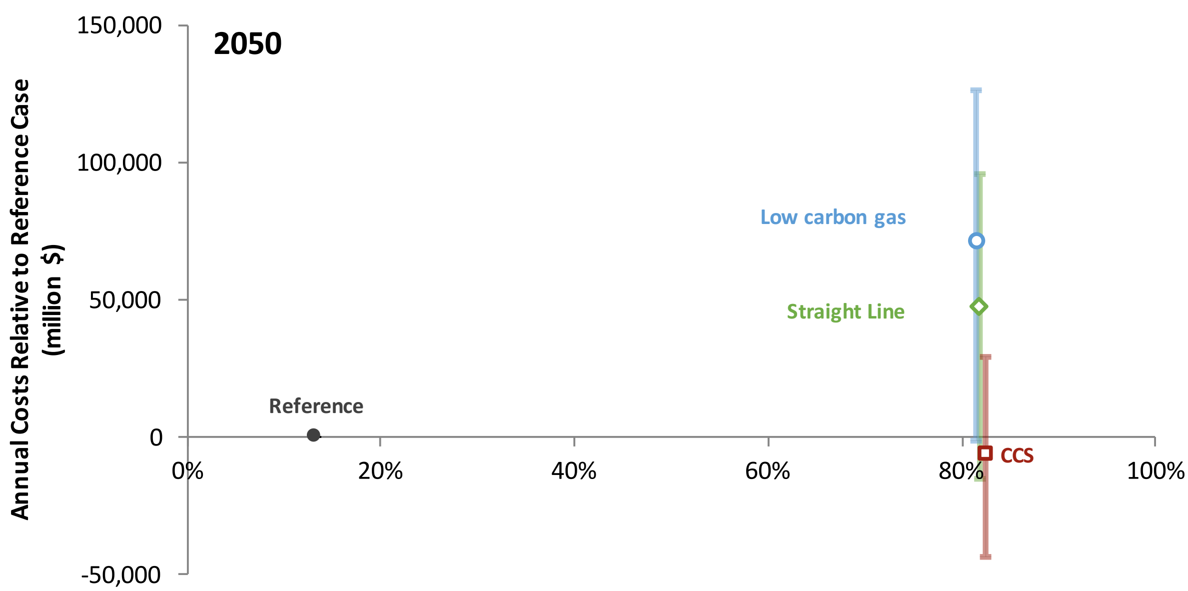


Figure 14. Scenario cost estimates for 2050. Costs are plotted on the vertical axis against GHG reduction (relative to the 1990 level) on the horizontal axis. CCS = Scenario A; Straight Line =

Scenario C; Low carbon gas = Scenario D.

In terms of annual costs, the CCS scenario trended fairly flat (i.e., close to reference case costs) between 2015 and 2050, and the base case estimate was actually slightly negative, saving an average of \$5.6 billion/yr between 2030 and 2050. The uncertainty range on this cost estimate was –\$26 to +41 billion/yr. See Figure 15.

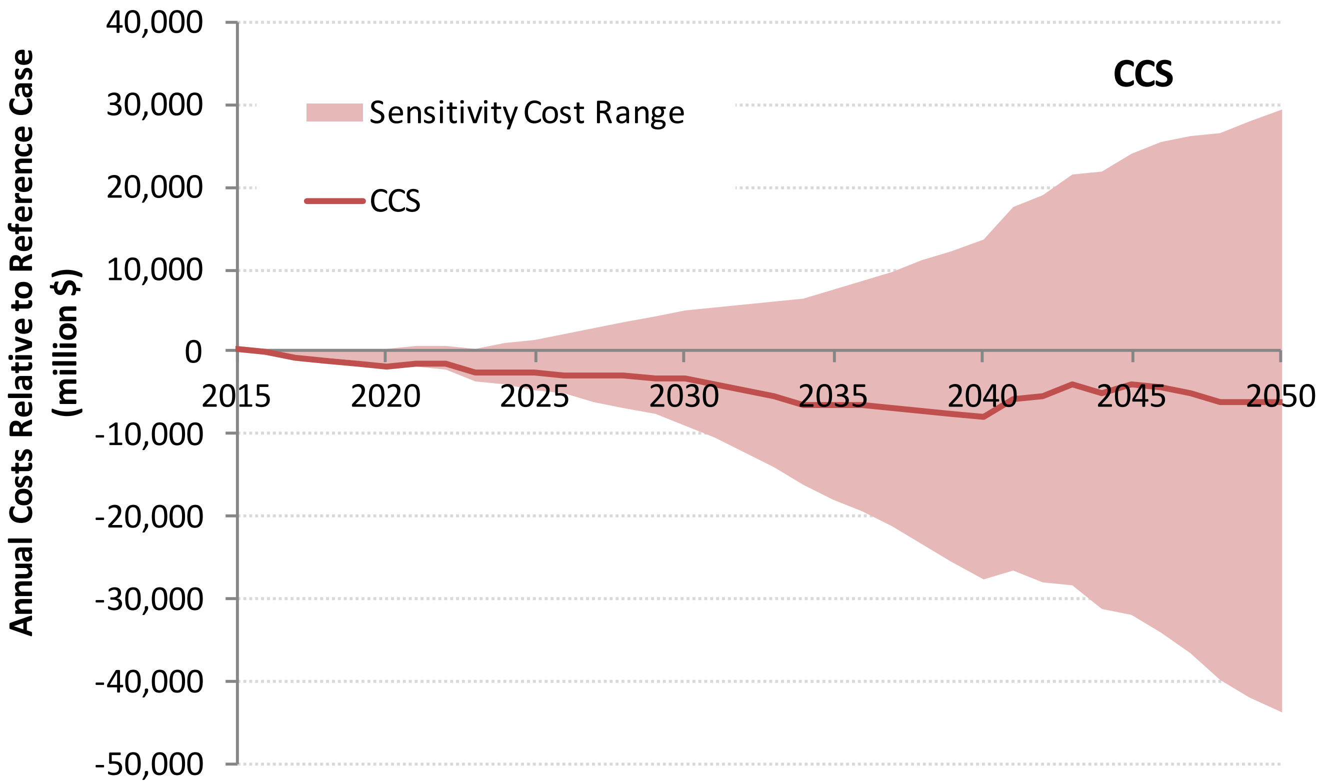


Figure 15. Annual CCS cost projections (equivalent to Scenario A)

The Straight Line scenario displayed steadily increasing costs after 2030, reaching a maximum of \$49 billion in 2048. The average 2030-2050 cost was \$25 billion/yr, with an uncertainty range of –\$6 to +\$57 billion/yr. See Figure 16.

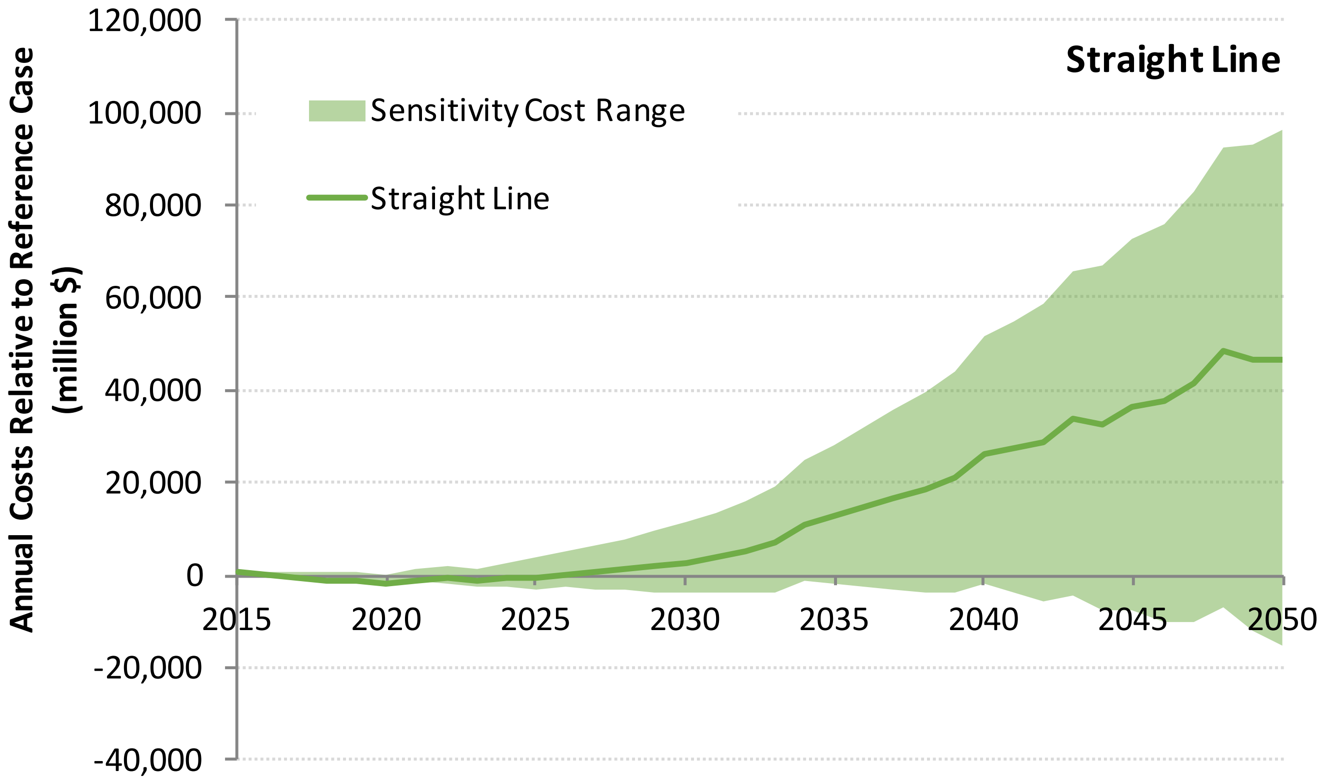


Figure 16. Annual Straight Line cost projections (equivalent to Scenario C)

The Low Carbon Gas scenario also displayed steadily increasing costs, with an earlier rise (after ~2025) and maximum cost of $71 billion in 2050. The average 2030-2050 cost was $41 billion/yr, with an uncertainty range of +$5 to +$64 billion/yr. See Figure 17.

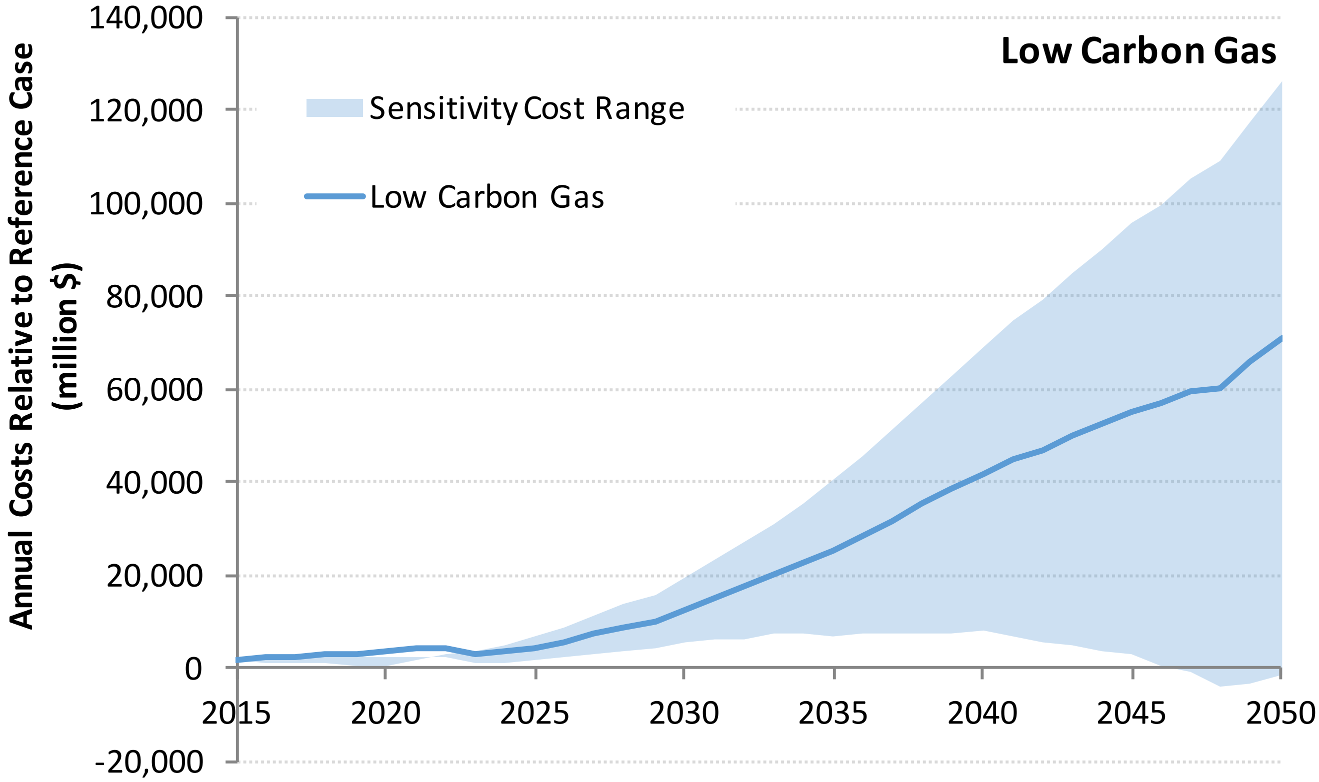


Figure 17. Annual Low Carbon Gas cost projections (equivalent to Scenario D)

Scale-up Rates

Historically, the fastest rates of growth in generation capacity in the U.S. electricity sector were seen in nuclear power and natural gas. Nuclear power grew from <1 GW to 100 GW installed capacity between 1965 and 1990, whereas natural gas grew from ~150 GW to ~400 GW between 1991 and 2009. Expressed in terms of a five-year running annual average growth rate (to smooth out noise in the data), there were two growth peaks for nuclear power, each at ~7 GW/yr: 1974 and 1985, whereas for natural gas, there was only one much larger peak (35 GW/yr) in 2001-2002. See Figure 18.

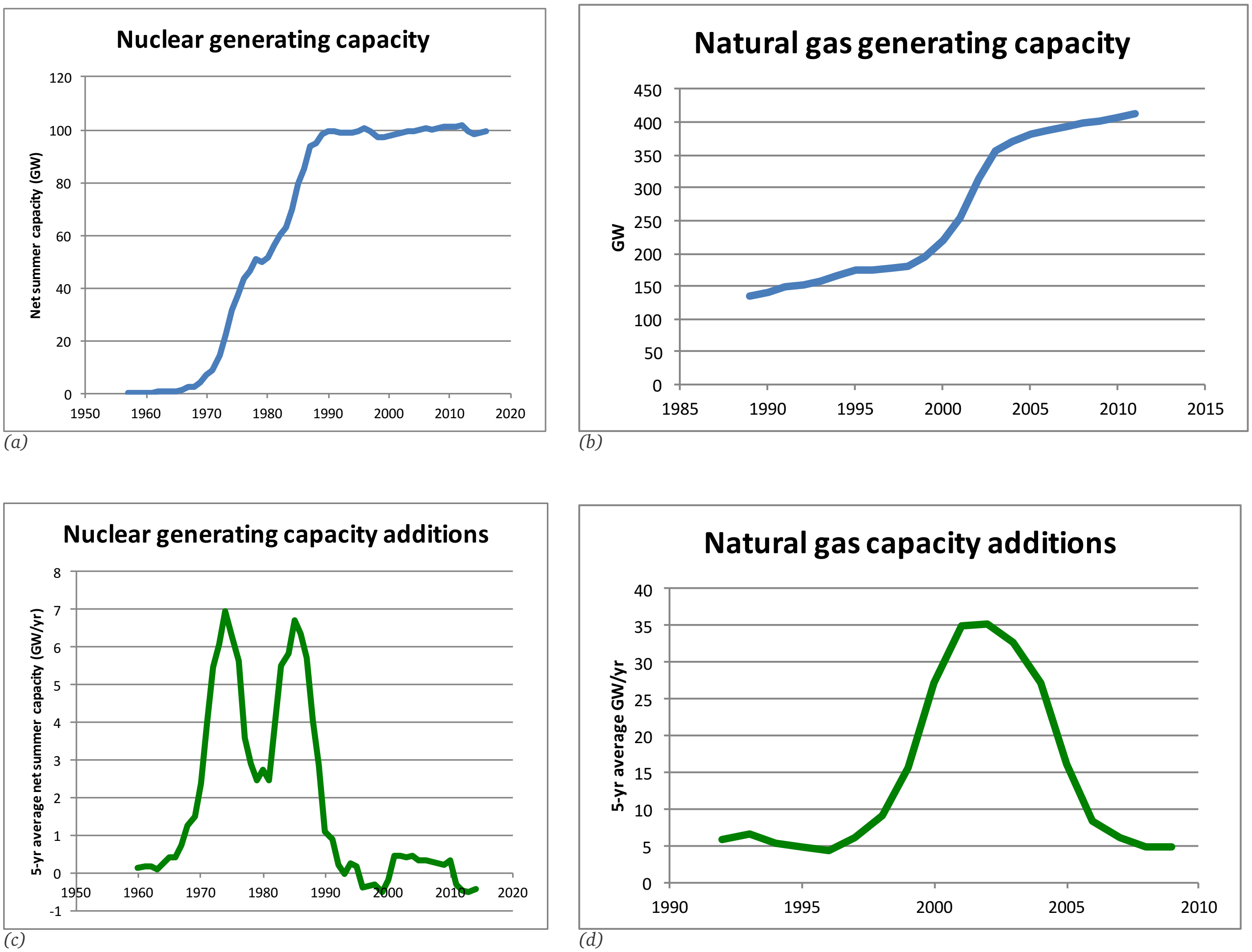
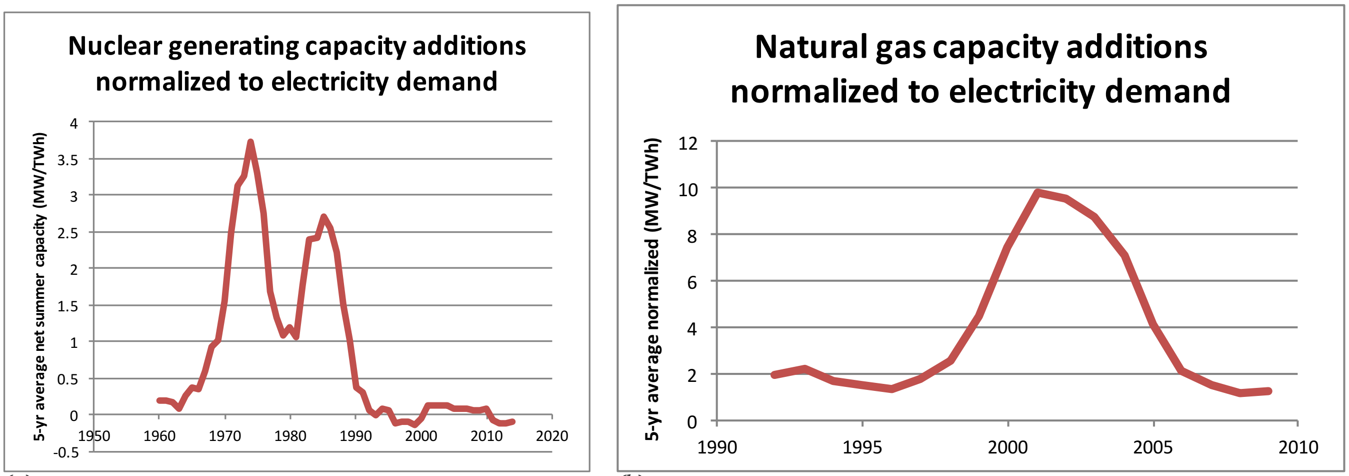


Figure 18. Historical growth of U.S. nuclear and natural gas electricity generation capacities: (a) Nuclear generating capacity (GW), (b) natural gas generating capacity (GW), (c) nuclear generating capacity average 5-yr addition rate (GW/yr), (d) natural gas generating capacity average 5-yr addition rate (GW/yr). Authors' analysis based on data from EIA (2011, 2017g).

In order to make these data more relevant to California, we have normalized them by the amount of net electricity generation (TWh) in each year, so the growth rate is expressed in terms of MW/yr per TWh/yr (or MW/TWh). Expressed this way, the maximum growth rate for nuclear power was 3.7 MW/TWh and for natural gas, 9.8 MW/TWh. These are shown in Figure 19.



(a) (b)

Figure 19. Normalized growth rates of nuclear and natural gas electricity generation capacity. Authors' analysis based on data from EIA (2011, 2017g, 2017h).

We now compare these historical growth rates to those for various types of electricity generation technologies modeled in the E3 scenarios.

Absolute growth rates

For the Straight Line (SL) and Low Carbon Gas (LCG) scenarios, while growth in most electricity generation technologies are modest, both of these scenarios have large ramp-up rates of wind and solar electricity generation after 2030, with peak five-year annual average build-out rates of ~9 GW/yr for wind and ~4.5 GW/yr for solar. Because both include increases in low-carbon gas resources, natural gas capacities also increase after 2030, reaching peaks of ~2 GW/yr. See Figure 20.

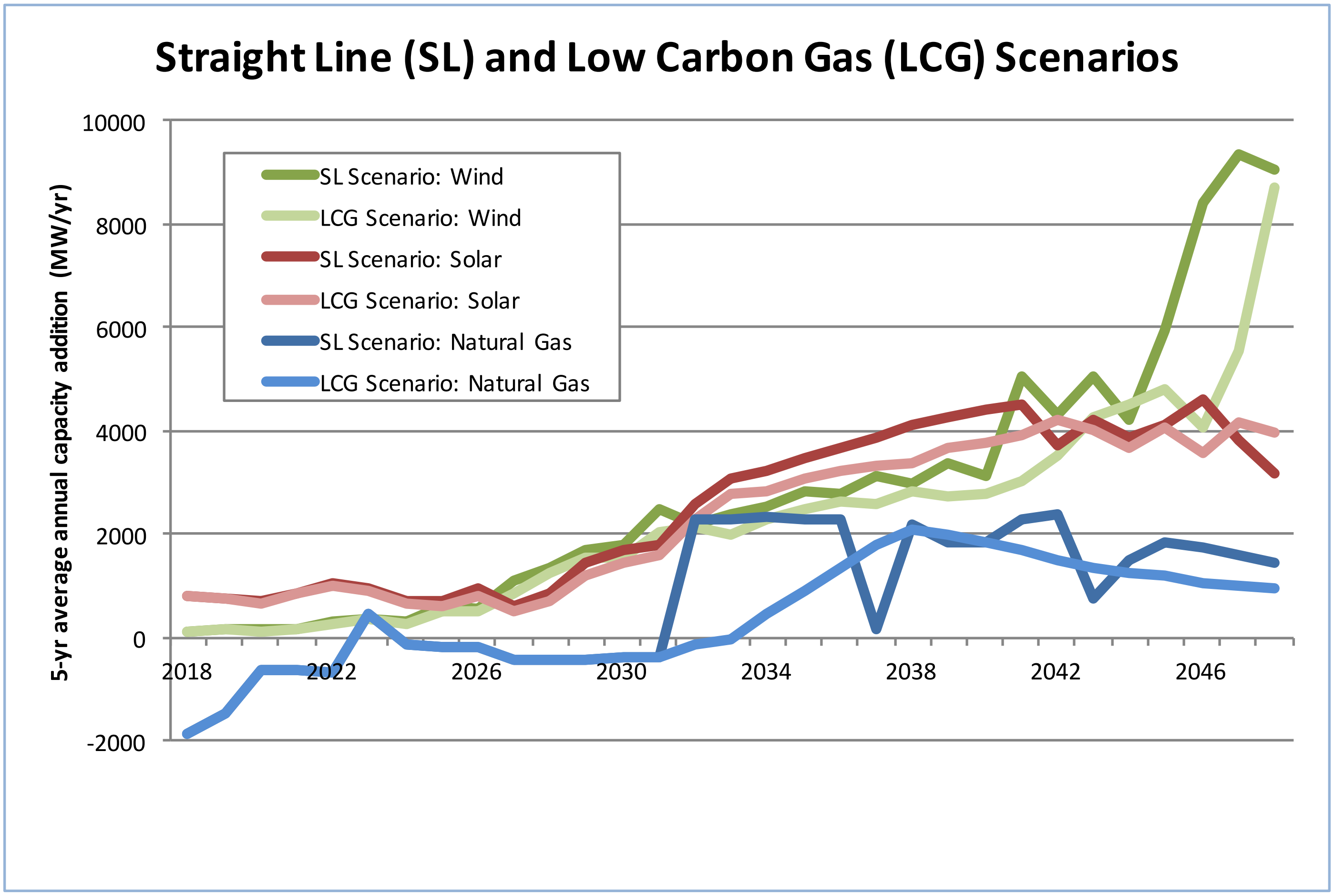


Figure 20. Required growth rates for SL and LCG scenarios

For the CCS scenario, as for the other scenarios, growth in most electricity generation technologies are modest in the CCS scenario, with the exception of natural gas with CCS, which exceeds 2.0 GW/yr after 2040, and peaks at 3.7 GW/yr in 2043-44. There is also a dramatic fall in non-CCS natural gas capacity that mirrors the growth in natural gas with CCS; its peak decline is –2.5 GW/yr in 2043-44. See Figure 21.

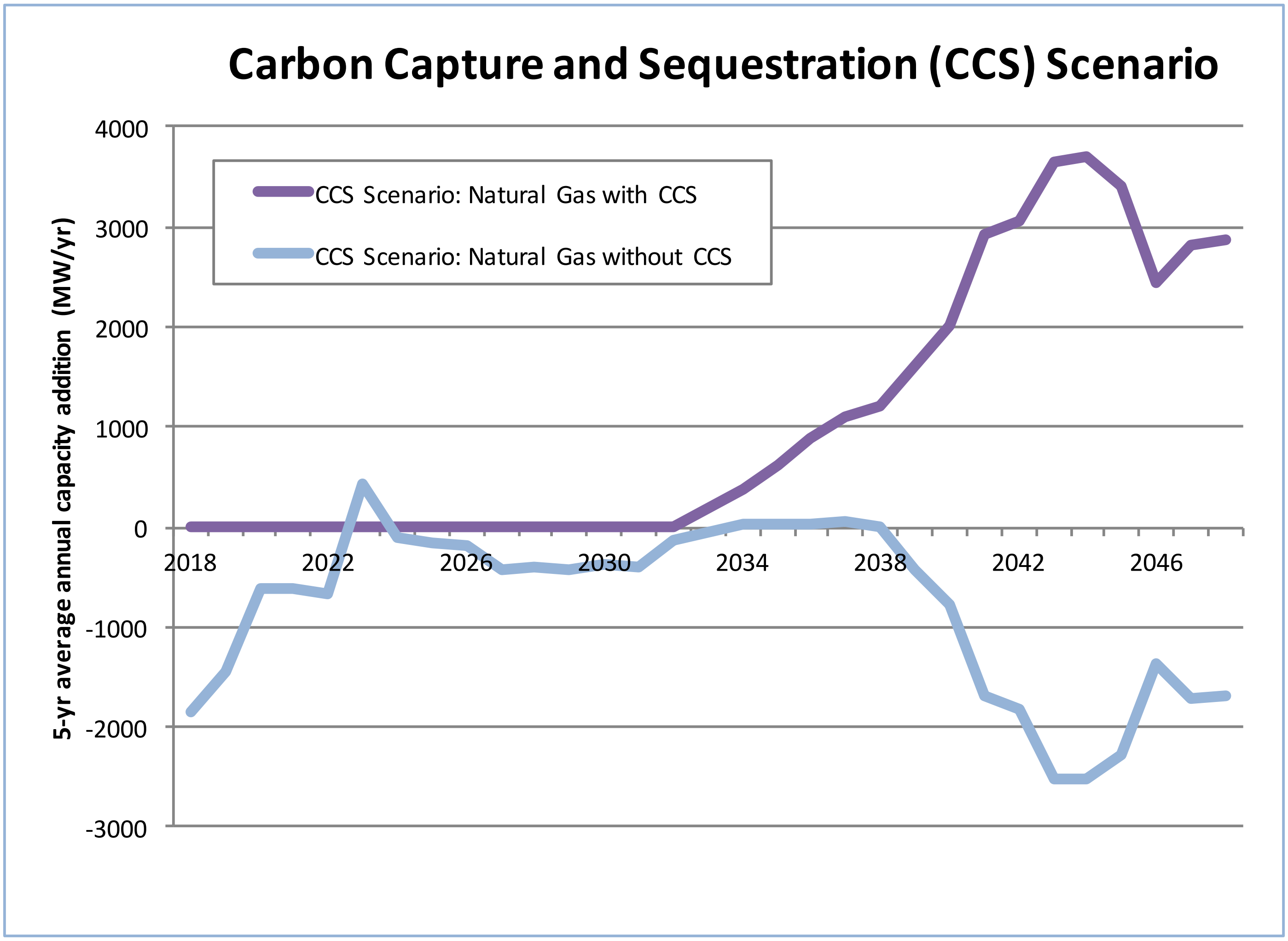


Figure 21. Required growth rates for CCS scenario

With the exception of wind, all of these growth rates are lower than peak growth in U.S. nuclear power, and all are well below the peak growth rate of U.S. natural gas. However, it may not be correct to compare California and national growth rates, so below we also examine growth rates normalized by electricity consumption.

Normalized growth rates

In Figure 22 and Figure 23, we have normalized growth rates for the three California scenarios as was done above for national growth rates for nuclear and natural gas. We have also indicated the historical peak growth rate for natural gas (9.8 MW/TWh) in the figures. Wind growth peaks at ~14.5 MW/TWh in both the SL and LCG scenarios, higher than the historical peak growth rate. However, the normalized solar rates are lower at ~8 MW/TWh.

For the CCS scenario, the normalized peak growth of natural gas with CCS is 8.3 MW/TWh. Both of these are below the historical peak growth rate for natural gas.

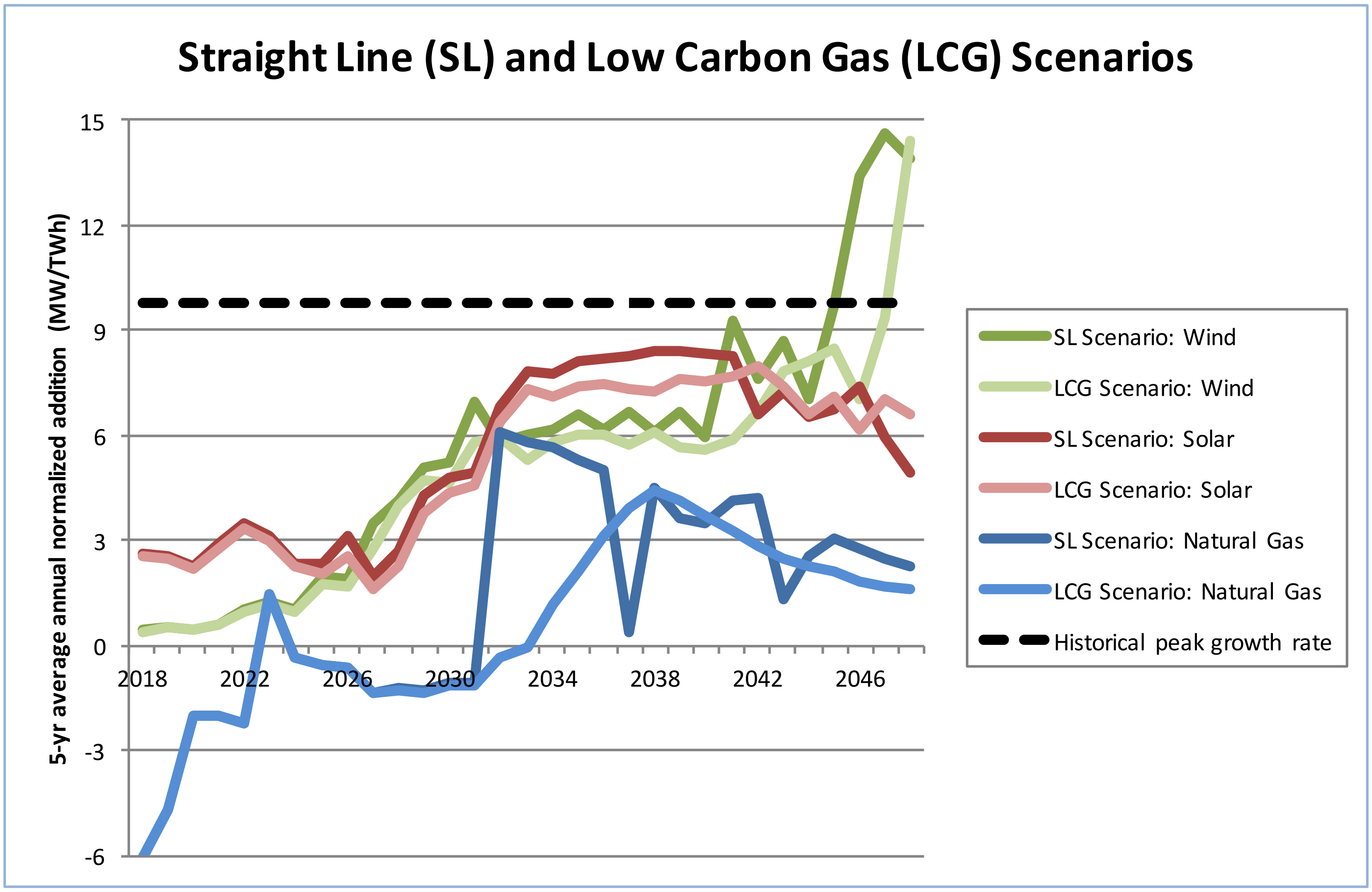


Figure 22. Normalized growth rates for Straight Line and Low Carbon Gas scenarios

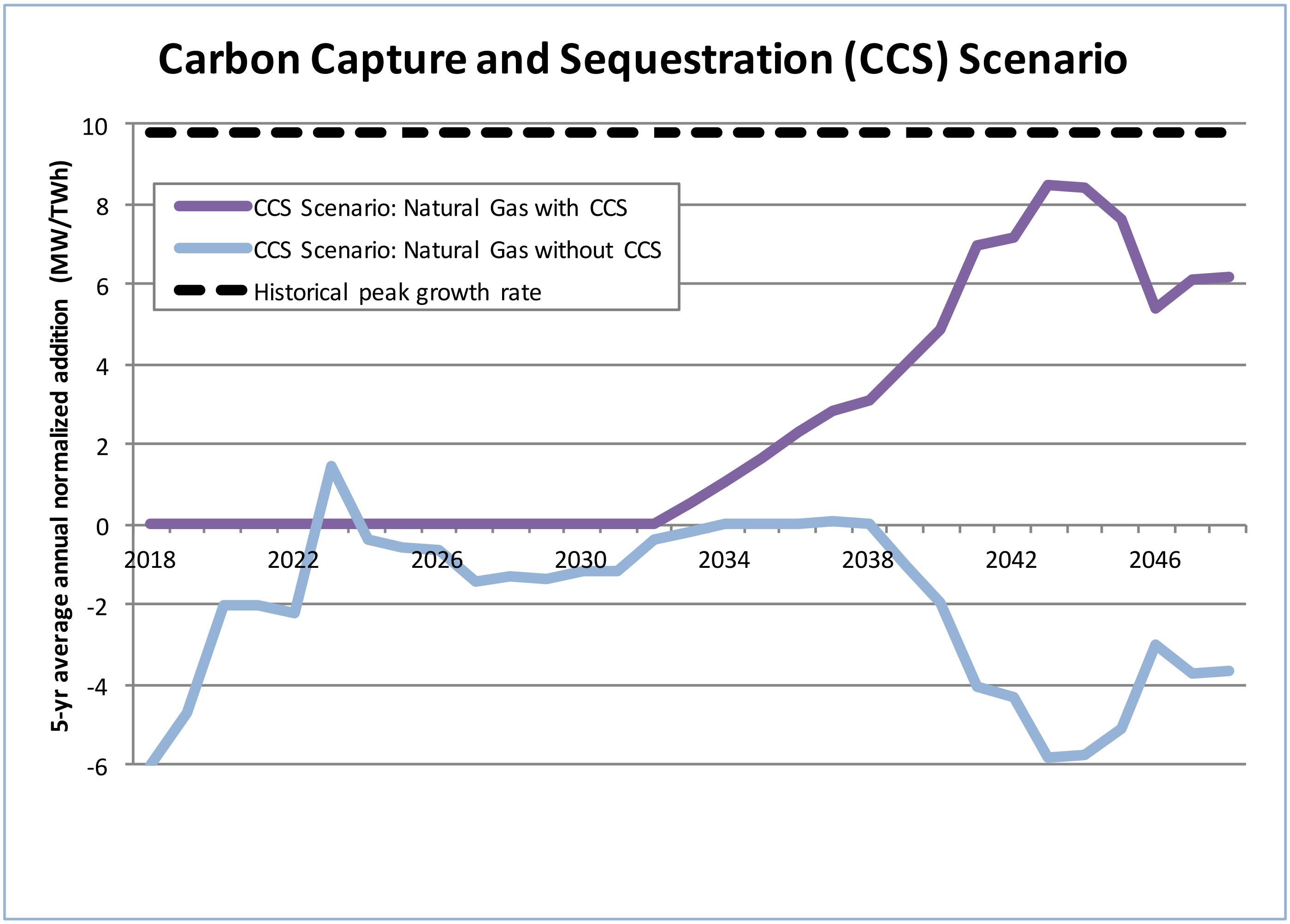


Figure 23. Normalized growth rates for CCS scenario

While it could be argued that the growth of wind in the SL and LCG scenarios exceeds the peak historical growth rate for natural gas, and therefore these scenarios should be excluded, many future scenarios for California invoke similar levels of renewable energy growth. Moreover, the balance of wind and solar capacity is dependent on future assumptions of relative costs, and it is entirely possible that the overall shares of wind and solar could be different. When we average the growth rates of these generation technologies, we find that the peak growth rates in each scenario are much closer (~10.5 MW/TWh) to the historical precedent. While still slightly exceeding the historical peak, we deemed these scenarios close enough to historical experience that we retained them in our analysis, with the caveat that build-out rates may be challenging to achieve.

Technical Resource for Biomethane

E3's (2015a) Low Carbon Gas scenario calls for ~60% biomethane in the pipeline mix by 2040, increasing from 33% biomethane in 2030 and negligible levels today. In addition, it calls for 8% SNG and 5% hydrogen in 2050, increasing from negligible levels in 2030. By comparison, the other two scenarios contain only 2% biomethane in 2030 and 5-12% in 2050, with similar levels of SNG and hydrogen.

Such an expansion would represent an unprecedented increase in the use of biomethane and other substitutes for natural gas. Biomethane is currently produced in 15 European countries in about 230 installations, and is injected into the natural gas grid in 11 countries (EBA, 2013a). Europe as a whole has set a target of 3% biomethane by 2030 (EBA, 2013b), and Germany, France, and Finland have set targets of 10% (EBA, 2013c; DENA, 2016; De Singly et al., 2016). Canada also has a target of 5% renewable natural gas blended with pipeline gas in 2025, and 10% by 2030 (CGA, 2016).

California could produce a maximum of ~250 MMcfd of biomethane from landfills, wastewater, municipal solid waste, and manure (Williams et al., 2015; Jaffe et al., 2016); an additional ~550 MMcfd would be available from woody biomass waste (BAC, 2014), but this technology is not yet mature. These resources would provide 4% and 13%, respectively, of current California natural gas demand. Clearly, these would be inadequate to meet the requirements of E3's Low Carbon Gas scenario. However, including out-of-state biomass resources could increase biomethane resources to as much as ~20,000 MMcfd (Murray et al., 2014), more than enough to satisfy ~50% of California's current natural gas demand even if California consumed no more than its population-weighted "fair share" (currently 12%) of this U.S. resource. Therefore, in principle, the target biomethane share of the Low Carbon Gas scenario could be met. For more details, see Appendix 3-2: Energy Technologies, Biomethane - Resources.

Note that these levels of biomethane generation would require significant development, as very little available biomass is currently converted into biogas for biomethane production. In particular, thermal gasification of agricultural and forest residues, which represents nearly all additional biomethane supply above $6/MMBtu in Murray et al., would have to be developed.

Appendix 3-5: Selected Data from E3 (2015a) Scenarios

In this Appendix, we provide details from three scenarios modeled by E3 (2015a) that closely resemble Scenarios A, C, and D in this chapter. E3 did not model a scenario that closely resembled Scenario B, however, so no data were available. See Table 8.

Table 8. Selected data from E3 (2015a) scenarios.

	2015	2030			2050		
E3 scenario name	**Straight Line**	**CCS**	**Straight Line**	**Low-Carbon Gas**	**CCS**	**Straight Line**	**Low-Carbon Gas**
CCST study scenario name	**N/A**	**Scenario A**	**Scenario C**	**Scenario D**	**Scenario A**	**Scenario C**	**Scenario D**
GHG reduction (% of 1990 level)	N/A	36%	38%	38%	82%	82%	81%
Pipeline gas demand							
Natural gas demand (EJ)	2.01	1.75	1.66	1.81	3.01	1.23	2.01
Fraction of 2015 gas demand	100%	87%	83%	90%	150%	61%	100%
Gas demand for electricity (EJ)	0.63	0.67	0.58	0.58	2.44	0.66	0.49
Gas demand for non-electricity (EJ)	1.38	1.08	1.08	1.23	0.58	0.58	1.52
Electricity share of pipeline gas demand	31%	38%	35%	32%	81%	53%	25%
Pipeline gas composition							
Biogas (biomethane) share	0%	2%	2%	33%	5%	12%	57%
Synthetic natural gas (SNG) share	0%	0%	0%	0.3%	0%	0%	8%
Hydrogen share	0%	0.2%	0.2%	0.2%	1%	3%	5%
Non-pipeline hydrogen demand (EJ)	0	0.06	0.06	0.06	0.43	0.47	0.04
Total gas demand (EJ)	2.01	1.81	1.72	1.87	3.44	1.70	2.05
Fraction of 2015 gas demand	100%	90%	86%	93%	171%	85%	102%
CO_2 sequestration (Mt/yr)	0	0	0	0	105	0	0
Electricity mix							
Electricity demand (TWh)	304	327	348	335	474	675	624
Renewable (excluding hydro) share of electricity generation	27%	39%	48%	47%	40%	80%	82%
Natural gas (including CHP) share of electricity generation	28%	29%	24%	25%	49%	13%	11%
Wind electricity share	10%	22%	22%	21%	24%	40%	41%
Solar electricity share	11%	11%	17%	17%	13%	36%	36%
Other (non-hydro) renewable electricity share	6%	6%	9%	9%	4%	5%	5%
New electric loads & storage							
Light-duty electric vehicles (M)	0.02	4.2	4.2	6.2	9.6	9.6	33
Heavy-duty electric vehicles (k)	0	2	45	104	682	1010	1218
Electric vehicle charging peak (GW)	0.02	2.3	2.5	4.0	3.6	3.7	15.0
Flexible load capacity (GW)	14	18	18	19	19	19	29
Electricity storage capacity (GW)	2.6	3.8	3.8	3.8	3.8	3.8	3.8
Building electric water and space heating loads (GBtu)	23	75	75	27	350	350	33
Heavy-duty natural gas vehicles (k)	33	38	38	166	43	43	1532

Appendix A

Study Charge

Project: Independent Review of Scientific and Technical Information on Long-Term Viability of Gas Storage

Background

The blowout of well Standard Sesnon 25 in the Aliso Canyon Field resulted in broad impacts that greatly exceeded those envisaged and prepared for both by the site operator and responsible government entities. The incident resulted in the temporary displacement of thousands of residents in the community surrounding the Aliso Canyon field and demonstrated vulnerabilities to the California energy supply chain that placed at risk the energy reliability to 21 million customers in the greater Los Angeles Basin. The broad health and environmental impacts are still being investigated as many of the contaminants released are known to be toxic at high doses but have limited health impact data for long-term chronic exposure. The event substantially increased the amount of methane emitted to the atmosphere for the entire state, and consequently the amount of greenhouse gas pollution emitted due to the state's economic activities.

Proclamation of a State of Emergency (see #14 below for study request)

WHEREAS on October 23, 2015, a natural gas leak was discovered at a well within the Aliso Canyon Natural Gas Storage Facility in Los Angeles County, and Southern California Gas Company's attempts to stop the leak have not yet been successful; and

WHEREAS many residents in the nearby community have reported adverse physical symptoms as a result of the natural gas leak, and the continuing emissions from this leak have resulted in the relocation of thousands of people, including many schoolchildren; and

WHEREAS major amounts of methane, a powerful greenhouse gas, have been emitted into the atmosphere; and

WHEREAS the Department of Conservation, Division of Oil, Gas and Geothermal Resources issued an emergency order on December 10, 2015 prohibiting injection of natural gas into the Aliso Canyon Storage Facility until further authorized; and

WHEREAS seven state agencies are mobilized to protect public health, oversee Southern California Gas Company's actions to stop the leak, track methane emissions, ensure worker safety, safeguard energy reliability, and address any other problems stemming from the leak; and

WHEREAS the California Public Utilities Commission and the Division of Oil, Gas and Geothermal Resources--working closely with federal, state and local authorities including the California Attorney General and the Los Angeles City Attorney--have instituted investigations of this natural gas leak and have ordered an independent, third-party analysis of the cause of the leak; and

NOW, THEREFORE, given the prolonged and continuing duration of this natural gas leak and the request by residents and local officials for a declaration of emergency, I, EDMUND G. BROWN JR., Governor of the State of California, in accordance with the authority vested in me by the State Constitution and statutes, including the California Emergency Services Act, HEREBY PROCLAIM A STATE OF EMERGENCY to exist in Los Angeles County due to this natural gas leak.

IT IS HEREBY ORDERED THAT:

1. All agencies of state government shall utilize all necessary state personnel, equipment, and facilities to ensure a continuous and thorough response to this incident, as directed by the Governor’s Office of Emergency Services and the State Emergency Plan.

2. The Governor’s Office of Emergency Services, in exercising its responsibility to coordinate relevant state agencies, shall provide frequent and timely updates to residents affected by the natural gas leak and the appropriate local officials, including convening community meetings.

STOPPING THE LEAK

3. The California Public Utilities Commission and the California Energy Commission shall take all actions necessary to ensure that Southern California Gas Company maximizes daily withdrawals of natural gas from the Aliso Canyon Storage Facility for use or storage elsewhere.

4. The Division of Oil, Gas and Geothermal Resources shall direct Southern California Gas Company to take any and all viable and safe actions to capture leaking gas and odorants while relief wells are being completed.

5. The Division of Oil, Gas and Geothermal Resources shall require Southern California Gas Company to identify how it will stop the gas leak if pumping materials through relief wells fails to close the leaking well, or if the existing leak worsens.

6. The Division shall take necessary steps to ensure that the proposals identified by Southern California Gas Company pursuant to Directives 4 and 5 are evaluated by the panel of subject matter experts the Division has convened from the Lawrence Berkeley, Lawrence Livermore, and Sandia National Laboratories to evaluate Southern California Gas Company’s actions.

PROTECTING PUBLIC SAFETY

7. The Division of Oil, Gas, and Geothermal Resources shall continue its prohibition against Southern California Gas Company injecting any gas into the Aliso Canyon Storage Facility until a comprehensive review, utilizing independent experts, of the safety of the storage wells and the air quality of the surrounding community is completed.

8. The California Air Resources Board, in coordination with other agencies, shall expand its real-time monitoring of emissions in the community and continue providing frequent, publicly accessible updates on local air quality.

9. The Office of Environmental Health Hazard Assessment shall convene an independent panel of scientific and medical experts to review public health concerns stemming from the gas leak and evaluate whether additional measures are needed to protect public health beyond those already put in place.

10. The California Public Utilities Commission and the California Energy Commission, in coordination with the California Independent System Operator, shall take all actions necessary to ensure the continued reliability of natural gas and electricity supplies in the coming months during the moratorium on gas injections into the Aliso Canyon Storage Facility.

ENSURING ACCOUNTABILITY

11. The California Public Utilities Commission shall ensure that Southern California Gas Company cover costs related to the natural gas leak and its response, while protecting ratepayers.

12. The California Air Resources Board, in consultation with appropriate state agencies, shall develop a program to fully mitigate the leak's emissions of methane by March 31, 2016. This mitigation program shall be funded by the Southern California Gas Company, be limited to projects in California, and prioritize projects that reduce short-lived climate pollutants.

STRENGTHENING OVERSIGHT OF GAS STORAGE FACILITIES

13. The Division of Oil, Gas and Geothermal Resources shall promulgate emergency regulations requiring gas storage facility operators throughout the state to comply with the following new safety and reliability measures:

    a. Require at least a daily inspection of gas storage well heads, using gas leak detection technology such as infrared imaging.

b. Require ongoing verification of the mechanical integrity of all gas storage wells.

c. Require ongoing measurement of annular gas pressure or annular gas flow within wells.

d. Require regular testing of all safety valves used in wells.

e. Establish minimum and maximum pressure limits for each gas storage facility in the state.

f. Require each storage facility to establish a comprehensive risk management plan that evaluates and prepares for risks at each facility, including corrosion potential of pipes and equipment.

14. The Division of Oil, Gas and Geothermal Resources, the California Public Utilities Commission, the California Air Resources Board and the California Energy Commission shall submit to the Governor's Office a report that assesses the long-term viability of natural gas storage facilities in California. The report should address operational safety and potential health risks, methane emissions, supply reliability for gas and electricity demand in California, and the role of storage facilities and natural gas infrastructure in the State's long-term greenhouse gas reduction strategies. This report shall be submitted within six months after the completion of the investigation of the cause of the natural gas well leak in the Aliso Canyon Storage Facility.

SB 826 Budget Act of 2016

"Of the amount appropriated in Schedule (3) of this item, $2,500,000 shall be allocated for a contract with the California Council on Science and Technology to conduct an independent study. The Public Utilities Commission, in consultation with the State Energy Resources Conservation and Development Commission, the State Air Resources Board, and the Division of Oil, Gas, and Geothermal Resources within the Department of Conservation, shall request the California Council on Science and Technology to undertake a study in accordance with Provision 14 of the Governor's Proclamation of a State Emergency issued on January 6, 2016. The study shall be conducted in a manner following well-established standard protocols of the scientific profession, including, but not limited to, the use of recognized experts, peer review, and publication, and assess the long-term viability of natural gas storage facilities in California. Specifically, the study shall address operational safety and potential health risks, methane emissions, supply reliability for gas and electricity demand in the state, and the role of storage facilities and natural gas infrastructure in the state's long-term greenhouse gas reduction strategies. The study shall be completed by December 31, 2017."

Appendix B

Scope of Work

The CCST study of natural gas storage in California will assess the long-term viability of gas storage facilities in California. The assessment will include an evaluation of the current state of the thirteen gas storage fields in California, a broad review of the potential health risks and community impacts associated with their operation, fugitive gas emissions, and the linkages between gas storage capacity and California's current and future energy needs. Recommendations to public policy makers will be made where appropriate.

Key questions for each of the report sections are identified in this Statement of Work, which will be a living document. The Steering Committee, in consultation with the CPUC, will review, modify and select the key questions from the list below to be addressed at a level of detail commensurate with the available funding for the report.

Objectives and Key Questions

Key Question 1: What risks do California's underground gas storage facilities pose to health, safety, environment, and infrastructure?

1. What are the different gas storage reservoir characteristics (e.g., storage in depleted gas or oil reservoirs, depth, lithology, hydrology, trap configuration, age of wells, etc.) and geographic settings surface characteristics (e.g., topography, elevation, vegetation, proximity to population, etc.) in California?

2. What are the potential failure modes involving gas release (e.g., large and sudden emissions of methane, fires and explosions, high-pressure gas releases)? What do we know about the likelihood of each of these failure modes at CA gas storage facilities and gathering lines today, e.g. based on documented past events? What are the potential emission rates and dispersion patterns of leaked gases? What are the consequences of the failure modes on gas storage infrastructure and consequently on delivery (e.g., wells, gathering lines, compressors, turbines, control equipment, etc.)?

3. What are the expected trends in capacity as storage facilities age, and as wells are taken out of service because of loss of reservoir integrity?

4. For various failure modes, what are the human health risks? What are the inventories of harmful substances available for release? For harmful constituents

found at low concentration in natural gas, including odorants, hydrogen sulfide, and aromatics what is the relationship between well-studied acute exposure impacts and potential longer-term (days to months) exposures to on-site workers and the communities near storage sites? What are the health risks to workers, nearby communities, and vulnerable populations of exposure to harmful substances, and/or to flames and explosions related to gas leakage? What are the health consequences of long-term low-flow rate leakage? What is the overall human health risk of various failure modes given their frequency and consequences?

5. What are the likely impacts of possible leakage, both from large emissions or long-term low-flow rate leakage, on California's greenhouse gas pollution budget? How do gas storage leaks compare to other fugitive emissions not covered by California's Cap and Trade program?

6. How will regulatory changes underway affect the integrity of storage? Are there practices beyond those specified in the new rules that might be useful in protecting the integrity of storage? In particular, can the assessment of a broader range of failure modes and consequences help set priorities for monitoring and intervention practices that will limit the most severe potential impacts? What are the key elements and level of detail required to develop effective risk management plans?

Key Question 2: Does California need underground gas storage to provide for energy reliability through 2020?

1. What is the current role of gas storage in California today? How has storage been designed to operate in different gas utility regions? What kind of and how much gas storage does California need to support its energy system, particularly in winter and summer extreme weather? What gas system benefits are derived from storage? What is the role of gas storage and arbitrage on California's core consumer energy prices?

2. How is the role of gas storage changing with powerful current and near term trends such as cheap gas, drought, decommissioning of nuclear power facilitates, national trends in fuel-switching to gas, increasing renewable portfolio standards, and the possible degradation of capacity of existing storage facilities, especially considering California's position at the "end of the pipeline" nationally? How might the role and infrastructure of both public and private gas storage change as a result.

3. How have historical storage facility performance problems impacted gas delivery and what have been the consequences for heating, electrical supply and industrial uses including refining?

4. Given the energy mix we will have in the near future, what would be required to replace gas storage facilities while maintaining reliability in supply under normal and extreme conditions? What infrastructure, regulatory and operational changes designed to optimize the use of existing infrastructure (such as balancing rules, nomination cycles and increased use of line pack) would be required? What may be the likely economic impact of these measures and what would the safety tradeoffs be? How do recent gas and electric market rule changes and those currently under consideration affect the role of storage and potential alternative resources to replace it? What are the potential costs and safety implications to implement energy infrastructure to replace gas storage facilities?

5. How are new requirements/regulations designed to improve integrity likely to affect the reliability of gas supply?

Key Question 3: How will implementation of California's climate polices change the need for underground gas storage in the future?

1. How could coordination of gas and electric operations reduce the need for storage? How may regional coordination of electric grid operation and planning change the role of gas/electric coordination and use of infrastructure?

2. What do changes in the energy system and possible changes anticipated to meet California's 2030 and 2050 climate goals imply for future gas usage and the need for gas? How might deployment of new technology impact the need for storage? In particular, what alternatives can feasibly replace or compete with gas storage in the deployment and integration of intermittent renewable energy? What practical economic and environmental impacts might these alternatives incur?

3. What does the assessment of storage that might be required to meet 2050 goals imply about storage in the interim time period?

Appendix C

CCST Steering Committee Members

The Steering Committee oversees the report authors, reaches conclusions based on the findings of the authors, and writes an executive summary. Lead authors and technical experts for each chapter also serve as Ex-Officio Steering Committee members.

Full *curricula vitae* for the Steering Committee members are available upon request. Please contact California Council on Science and Technology (916) 492-0996.

Steering Committee Members

- **Jens T. Birkholzer**, Co-Chair, Lawrence Berkeley National Laboratory
- **Jane C.S. Long**, Co-Chair, Independent Consultant
- **J. Daniel Arthur**, ALL Consulting LLC
- **Riley M. Duren**, NASA Jet Propulsion Laboratory
- **Karen Edson**, retired California Independent System Operator
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Jens T. Birkholzer, Ph.D., Co-Chair

Director, Energy Geosciences Division, Lawrence Berkeley National Laboratory

Dr. Jens Birkholzer is a Senior Scientist at the Lawrence Berkeley National Laboratory (LBNL, Berkeley Lab). As an internationally recognized expert in subsurface energy applications and environmental impact assessment, he currently serves as the Director for the Energy Geosciences Division (EGD) in the Earth and Environmental Sciences Area (EESA). He received his Ph.D. in water resources, hydrology, and soil science from Aachen University of Technology in Germany in 1994. Dr. Birkholzer joined LBNL in 1994, left for a management position in his native Germany in 1999, and eventually returned to LBNL in 2001. He has over 400 scientific publications, about 130 of which are in peer-reviewed journals, in addition to numerous research reports. He serves as the Associate Editor of the International Journal of Greenhouse Gas Control (IJGGC) and is also on the Board of Editorial Policy Advisors for the Journal of Geomechanics for Energy and Environment (GETE). Dr. Birkholzer leads the international DECOVALEX Project as its Chairman, is a Fellow of the Geological Society of America, and serves as a Senior Fellow of the California Council on Science and Technology.

Jane C.S. Long, Ph.D., Co-Chair

Independent Consultant and CCST Council Member

Dr. Long holds a ScB in biomedical engineering from Brown University, an MS and PhD in hydrology from U.C. Berkeley. She formerly was Associate Director for Energy and Environment at Lawrence Livermore National Laboratory, Dean of Mackay School of Mines at the University of Nevada, Reno; and a scientist and department chair in energy and environment for Lawrence Berkeley National Laboratory. Dr. Long is an advisor for the Environmental Defense Fund, on the board of directors for Clean Air Task Force and the Bay Area Air Quality Management District Scientific Advisory Board. She is a fellow of the American Association for the Advancement of Science, an Associate of the National

Academies of Science (NAS) and a Senior Fellow of the California Council on Science and Technology (CCST). She was Alum of the Year in 2012 for the Brown University School of Engineering and Woman of the Year for the California Science Center in 2017.

J. Daniel Arthur, P.E., SPEC

President, Petroleum Engineer, Program Manager, ALL Consulting

Mr. Arthur is a registered professional petroleum engineer specializing in fossil energy, planning/engineering, the entire lifecycle of water, resource development best practices, gas storage, and environmental/regulatory issues. He has 30 years of diverse experience that includes work in industry, government, and consulting. Mr. Arthur is a founding member of ALL Consulting and has served as the company's President and Chief Engineer since its inception in 1999.

Prior to founding ALL Consulting, Mr. Arthur served as a Vice President of a large international consulting engineering firm and was involved with a broad array of work, including supporting the energy industry, various federal agencies, water and wastewater projects (municipal/industrial), environmental projects, various utility related projects, and projects related to the mining industry. Mr. Arthur's experience also includes serving as an enforcement officer and National Expert for the U.S. Environmental Protection Agency (EPA) and a drilling and operations engineer with an independent oil producer, as well as direct work with an oilfield service company in the mid-continent.

In 2016, Mr. Arthur was appointed to serve on a Steering Committee for Natural Gas Storage for the California Council on Science and Technology. Mr. Arthur's role on the Committee is primarily focused on well construction, integrity and testing based on his expertise, but also included overall analysis on issues such as global climate change and other issues (e.g., induced seismicity, gas markets, etc.). In 2010, as the shale boom was heightening, Mr. Arthur was appointed to serve as a Sub-Group Leader for a National Petroleum Council study on North American Resource Development. His Sub-Group focused on technology that is and will be needed to address development (e.g., hydraulic fracturing, horizontal drilling, production, etc.) and environmental challenges through the year 2050. Mr. Arthur was also appointed to a U.S. Department of Energy Federal Advisory Committee on Unconventional Resources. And lastly, Mr. Arthur supported the U.S. Department of Energy through the Annex III Agreement between the United States and China to provide support relative to coal bed methane and shale gas development in China.

Mr. Arthur routinely serves as a testifying and/or consulting expert on a broad variety of issues that range from basic engineering to catastrophic incidents. He has also served to advise management and legal teams on a plethora of issues in an effort to avoid litigation, reach settlements, or develop strategies for future activities. His experience and continued level of activity on such issues has expanded his experience on a variety of issues, while also exposing him to an array of technical and forensic approaches to assess past activities, claims, etc. Mr. Arthur is also a member of the National Association of Forensic Engineers (NAFE).

Mr. Arthur has managed an assortment of projects, including regulatory analysis (e.g., new regulation development process, commenting/strategizing on new proposed regulations, negotiating with regulatory agencies on proposed regulations, analysis of implementation impacts, etc.); engineering design (including roads, well pads, design of various types of wells; completions/fracturing; water and wastewater systems, and oil & gas facilities); life cycle analysis and modeling; resource evaluations; energy development alternatives analysis (e.g., oil, gas, coal, electric utility, etc.); feasibility analyses (including power plants, landfills, injection wells, water treatment systems, mines, oil & gas plays, etc.); remediation and construction; site closure and reclamation site decommissioning; reservoir evaluation; regulatory permitting and environmental work; geophysical well logging; development of new mechanical integrity testing methods, standards, and testing criteria; conduction and interpretation of well tests; restorative maintenance on existing wells and well sites; extensive hydrogeological and geochemical analysis of monitoring and operating data; sophisticated 2-dimensional and 3-dimensional modeling; geochemical modeling; drilling and completion operations; natural resource and environmental planning; natural resource evaluation; governmental and regulatory negotiations; restoration and remediation; environmental planning, design, and operations specific to the energy industry in environmentally sensitive areas; water management planning; alternative analysis for managing produced water; beneficial use of produced water; water treatment analysis and selection; produced water disposal alternatives; facilities engineering for wastewater handling (e.g., disposal wells, injection wells, water treatment, water recycling, water blending, etc.); construction oversight; contract negotiations and management; contract negotiation with wastewater treatment companies accepting produced water; data management related to water and environmental issues; property transfer environmental assessments; and data management of oil and gas producing and related injection well data and information. He maintains experience with the technical and regulatory aspects of oil and gas and underground injection throughout North America. He has given presentations, workshops, and training sessions to groups and organizations on an assortment of related issues and has provided his consulting expertise to hundreds of large and small clients - including several major international energy companies and government agencies.

Specific to unconventional resource development, Mr. Arthur has gained experience in all aspects of planning, development, operations, and closure. Mr. Arthur has supported the evolution of various activities through this process that have included technical issues such as water sourcing, well drilling techniques, cement design, well integrity analysis, fracturing design & analysis, well performance assessment, production operations and facilities, well plugging & abandonment, site closures, and regulatory compliance. Mr. Arthur's experience covers ever major unconventional play in North America and on other continents. Moreover, Mr. Arthur's experience also includes work with horizontal drilling and various types of completions in both conventional and unconventional reservoirs and with various types of unconventional reservoirs (e.g., shales, limestones, coal).

Riley M. Duren

Principal Engineer, Earth Science & Technology Directorate,
NASA Jet Propulsion Laboratory

Mr. Riley Duren is Chief Systems Engineer for the Earth Science and Technology Directorate at NASA's Jet Propulsion Laboratory. He received his BS in electrical engineering from Auburn University in 1992. He has worked at the intersection of engineering and science including seven space missions ranging from earth science to astrophysics. His current portfolio spans JPL's earth system science enterprise as well as applying the discipline of systems engineering to climate change decision-support. His research includes anthropogenic carbon emissions and working with diverse stakeholders to develop policy-relevant monitoring systems. He is Principal Investigator for five projects involving anthropogenic carbon dioxide and methane emissions. He has also co-led studies on geoengineering research, monitoring, and risk assessment. He is a Visiting Researcher at UCLA's Joint Institute for Regional Earth System Science and Engineering and serves on the Advisory Board for NYU's Center for Urban Science and Progress.

Karen Edson

Vice-President of Policy and Client Services,
California Independent System Operator (ISO), Retired

Ms. Karen Edson has nearly 40 years of experience involving state and federal energy issues. Most recently, she served as Vice-President of Policy and Client Services for the California Independent System Operator (ISO) from 2005 until her retirement in 2016. She performed a key role in building and maintaining strategic partnerships with responsibilities that included overseeing the outreach and education needs of a diverse body of stakeholders, state and federal regulators and policy makers. She was also a leader of internal policy development and oversaw internal and external communications. Her work in the energy field began in the seventies as a legislative aide and state agency government affairs director, leading to her appointment to the California Energy Commission by Governor Jerry Brown in 1981. After her term ended, she founded a small consulting firm that represented non-utility interests including geothermal and solar energy providers, industrial firms with combined heat and power, electric vehicle interests, and several trade associations. Ms. Edson holds a Bachelor's degree from the University of California Berkeley.

Catherine M. Elder, M.P.P.

Practice Director, Energy Economics, Aspen Environmental Group

Elder has 30 years of experience working in the natural gas and electric generation business and leads Aspen's Energy Economics practice, specializing in assistance to state energy agencies, public power entities and others. Elder worked on both federal and state-level natural gas industry restructuring as an employee of Pacific Gas and Electric Company beginning in the mid-1980's. She has reviewed fuel plans and advised lenders providing nonrecourse financing to more than 40 different gas-fired power projects across the U.S. and Canada, and has served as the Chief Gas Price Forecaster both for consultancy R.W. Beck and for the State of California's then-record $13 Billion financing of purchased power arising from the 2000-2001 power crisis. She holds a Master in Public Policy from the John F. Kennedy School of Government at Harvard University and an undergraduate degree in Political Economy (with Honors) from the University of California, Berkeley.

In starting her career at PG&E, Elder helped develop the policies and rules that to this day govern the natural gas market and regulatory framework in California. These include the unbundling of gas from transportation, the development of independent gas storage, and efforts to allow larger customers and marketers to bid for pipeline capacity in an auction whose results would have been used to establish priority of service. (The latter was abandoned in favor of a simpler mechanism in settlement.)

Since leaving PG&E in 1991, Elder worked for two years at law firm Brady & Berliner as its internal consultant, working often with Canadian natural gas producers selling natural gas in the U.S. She then joined Morse, Richard, Weisenmiller & Associates as a Senior Project Manager in Oakland, CA. From 1998 to 2003 she was a Principal Executive Consultant at Resource Management, Inc, in Sacramento, which ultimately became Navigant Consulting. At Navigant she performed independent reviews of natural gas markets, gas arrangements and disconnects between electricity and natural gas markets in support of nonrecourse financing by large financial institutions. She also reviewed the gas arrangement included in many of the tolling agreements put in place by the California Department of Water Resources during the 2000-2001 power crisis and developed the natural gas price forecast used by the state to project gas and electricity costs underlying the associated $13 Billion bond financing. In 2003 she joined consultancy RW Beck, as its natural gas market expert and chief price forecaster, and in 2009 joined Aspen Environmental Group. At Aspen, Elder leads the Energy Economics practice. Key clients have included the American Public Power Association, for whom she authored a major report in 2010 entitled "Implications of Greater Reliance on Natural Gas for Electricity Generation," and the California Energy Commission. Elder has served as the independent fuel consultant for lenders to more than 40 natural gas-fired power projects across the U.S. and Canada.

Jeffery B. Greenblatt, Ph.D.

Staff Scientist, Energy Analysis and Environmental Impacts Division,
Lawrence Berkeley National Laboratory

Jeffery Greenblatt has been involved with modeling pathways of low-carbon energy future since 2006. He has published a number of studies including the groundbreaking California's Energy Future study (sponsored California Council on Science and Technology), an analysis of California greenhouse gas policies in Energy Policy, an analysis of US policies in Nature Climate Change, and a review of the future of low-carbon electricity forthcoming in Annual Review of Environment and Resources. He also works on the life-cycle assessment of emerging technologies including artificial photosynthesis and autonomous vehicles, was involved with both DOE's Quadrennial Technology Review and Quadrennial Energy Review efforts, and recently started a consulting company focused on space technologies. He has more than 15 years of experience in climate change and low-carbon energy technology assessment and modeling. Prior to joining LBNL in 2009, Dr. Greenblatt worked at Google on the Renewable Electricity Cheaper than Coal initiative,
at Environmental Defense Fund as an energy scientist, at Princeton University as a research staff member, and at NASA Ames as a National Research Council associate.
He received a Ph.D. in chemistry from UC Berkeley in 1999.

Robert B. Jackson, Ph.D.

Professor and Chair, Earth Sciences Department, Stanford University

Robert B. Jackson is Michelle and Kevin Douglas Provostial Professor and chair of the department of Earth System Science in the School of Earth, Energy & Environmental Sciences. He studies how people affect the earth, including research on the global carbon and water cycles, biosphere/atmosphere interactions, energy use, and climate change.

Jackson has received numerous awards. He is a Fellow in the American Geophysical Union and the Ecological Society of America and was honored at the White House with a Presidential Early Career Award in Science and Engineering. In recent years, he directed the DOE National Institute for Climate Change Research for the southeastern U.S., co-chaired the U.S. Carbon Cycle Science Plan, and is currently CHAIR of the Global Carbon Project (www.globalcarbonproject.org).

An author and photographer, Rob has published a trade book about the environment (The Earth Remains Forever, University of Texas Press) and two books of children's poems, Animal Mischief and Weekend Mischief (Highlights Magazine and Boyds Mills Press). His photographs have appeared in many media outlets, including the NY Times, Washington Post, USA Today, US News and World Report, Nature, and National Geographic.

Michael L.B. Jerrett, Ph.D.

Professor and Chair, Department of Environmental Health Sciences,
University of California, Los Angeles

Dr. Michael Jerrett is an internationally recognized expert in Geographic Information Science for Exposure Assessment and Spatial Epidemiology. He is a full professor and the chair of the Department of Environmental Health Science, and Director of the Center for Occupational and Environmental Health, Fielding School of Public Health, University of California, Los Angeles. Dr. Jerrett is also a professor in-Residence in the Division of Environmental Health Sciences, School of Public Health, University of California, Berkeley. Dr. Jerrett earned his PhD in Geography from the University of Toronto. Over the past 20 years, Dr. Jerrett has researched how to characterize population exposures to air pollution and built environmental variables, the social distribution of these exposures among different groups (e.g., poor vs. wealthy), and how to assess the health effects from environmental exposures. He has worked extensively on how the built environment affects exposures and health, including natural experimental design studies. He has published some of the most widely-cited papers in the fields of Exposure Assessment and Environmental Epidemiology in leading journals, including The New England Journal of Medicine, The Lancet, and Proceedings of the National Academy of Science of the United States of America, and Nature. In 2009, the United States National Academy of Science appointed Dr. Jerrett to the Committee on "Future of Human and Environmental Exposure Science in the 21st Century." The Committee concluded its task with the publication of a report entitled Exposure Science in the 21st Century: A Vision and a Strategy. In 2014 and 2015, he was named to the Thomson-Reuters List of Highly-Cited Researchers, indicating he is in the top 1% of all authors in the fields of Environment/Ecology in terms of citation by other researchers. In 2016, Dr. Jerrett was appointed to the National Academy of Science Standing Committee on Geographical Sciences.

Najmedin Meshkati, Ph.D.

Professor, Department of Civil and Environmental Engineering
Department of Industrial and Systems Engineering, University of Southern California

Dr. Najmedin Meshkati is a (tenured, full) Professor of Civil/Environmental Engineering; Industrial & Systems Engineering; and International Relations at the University of Southern California (USC). He was a Jefferson Science Fellow and a Senior Science and Engineering Advisor, Office of Science and Technology Adviser to the Secretary of State, US State Department, Washington, DC (2009-2010). He is a Commissioner of The Joint Commission (2016-; a not-for-profit organization that accredits and certifies nearly 21,000 healthcare organizations and programs in the United States and operates in 92 countries around the world, http://www.jointcommission.org/) and is on the Board of Directors of the Center for Transforming Healthcare. He has served as a member of the Global Advisory Council of the Civilian Research and Development Foundation (CRDF) Global, chaired by Ambassador Thomas R. Pickering (2013-2016).

For the past 30 years, he has been teaching and conducting research on risk reduction and reliability enhancement of complex technological systems, including nuclear power, aviation, petrochemical and transportation industries. He has been selected by the US National Academy of Sciences (NAS), National Academy of Engineering (NAE) and National Research Council (NRC) for his interdisciplinary expertise concerning human performance and safety culture to serve as member and technical advisor on two national panels in the United States investigating two major recent accidents: The NAS/NRC Committee “Lessons Learned from the Fukushima Nuclear Accident for Improving Safety and Security of U.S. Nuclear Plants” (2012-2014); and the NAE/NRC “Committee on the Analysis of Causes of the Deepwater Horizon Explosion, Fire, and Oil Spill to Identify Measures to Prevent Similar Accidents in the Future” (2010-2011).

Dr. Meshkati has inspected many petrochemical and nuclear power plants around the world, including Chernobyl (1997), Fukushima Daiichi and Daini (2012). He has worked with the U.S. Chemical Safety and Hazard Investigation Board, as an expert on human factors and safety culture, on the investigation of the BP Refinery explosion in Texas City (2005), and served as a member of the National Research Council (NRC) Committee on Human Performance, Organizational Systems and Maritime Safety. He also served as a member of the NRC Marine Board’s Subcommittee on Coordinated R&D Strategies for Human Performance to Improve Marine Operations and Safety.

Dr. Meshkati is the only full-time USC faculty member who has continuously been conducting research on human factors and aviation safety-related issues (e.g., cockpit design and automation, crew resource management, safety management system, safety culture, and runway incursions,) and teaching in the USC 63-year old internationally renowned Aviation Safety and Security Program, for the past 25 years. During this period, he has taught in the “Human Factors in Aviation Safety” and “System Safety” short courses. From 1992 to 1999, he also was the Director and had administrative and academic responsibility for the USC Professional Programs, which included Aviation Safety, as well as for the Transportation Safety, and Process Safety Management (which he designed and developed) programs. He has worked with numerous safety professionals from all over the world and has taught safety short courses for private and public sector organizations, including the US Navy, US Air Force, US Forest Service, California OSHA, Celgene, Metrolink, Exelon, the Republic of Singapore Air Force, Singapore Institution of Safety Officers, China National Petrochemical Corporation, Canadian upstream oil and gas industry (Enform), Korea Hydro and Nuclear Power (KHNP), Ministry of Foreign Affairs (Republic of Korea), etc.

Dr. Meshkati is an elected Fellow of the Human Factors and Ergonomics Society (HFES); the 2015 recipient of the HFES highest award, the Arnold M. Small President's Distinguished Service Award, for his "career-long contributions that have brought honor to the profession and the Society"; and the 2007 recipient of the HFES Oliver Keith Hansen Outreach Award for his "scholarly efforts on human factors of complex, large-scale technological systems." He is the inaugural recipient of the Ernest Amory Codman Lectureship and Award (form The Joint Commission for his leadership and efforts in continuously improving the safety and quality of care). He is an AT&T Faculty Fellow in Industrial Ecology, a NASA Faculty Fellow (Jet Propulsion Laboratory, 2003 and 2004), and a recipient of the Presidential Young Investigator Award from the National Science Foundation (NSF) in 1989.

He has received numerous teaching awards at USC, which include the 2013 Steven B. Sample Teaching and Mentoring Award from the USC Parents Association, the 2000 TRW Award for Excellence and Outstanding Achievement in Teaching from the USC Viterbi School of Engineering; the 1996, 2003, 2006, 2007, 2008 and 2016 Professor of Year Award (Excellence in Teaching and Dedication to Students Award) from the Daniel J. Epstein Department of Industrial & Systems Engineering; the Mortar Board's Honored Faculty Award (2007-2008) from the University of Southern California's Chapter of the Mortar Board; and the Outstanding Teaching Award from The Latter-day Saint Student Association at USC (April 11, 2008). He was chosen as a Faculty Fellow by the Center for Excellence in Teaching, USC (2008-2010).

He is the co-editor and a primary author of the book Human Mental Workload, North-Holland, 1988. His articles on public policy; the risk, reliability, and environmental impact of complex, large-scale technological systems; and foreign policy-related issues have been published in several national and international newspapers and magazines such the New York Times, International New York Times (International Herald Tribune), Los Angeles Times, Washington Post, Baltimore Sun, Houston Chronicle, Sacramento Bee, MIT Technology Review, Japan Times, Korea Herald (South Korea), Gulf Today (Sharjah, UAE), Times of India, Hurriyet Daily News (Istanbul, Turkey), Strait Times (Singapore), Iran News (Tehran, Iran), South China Morning Post (Hong Kong), Winnipeg Free Press, Waterloo Region Record, Windsor Star (Canada), Scientific Malaysian, etc.

As chairman of the "group of expects" of the International Ergonomics Association (IEA), Dr. Meshkati coordinated international efforts which culminated in the joint publication of the United Nations' International Labor Office (ILO) and IEA Ergonomic Checkpoints: Practical and Easy-to-Implement Solutions for Improving Safety, Health and Working Conditions book in 1996, for which he received the Ergonomics of Technology Transfer Award from the IEA in 2000. According to the ILO, this book has so far been translated and published into 16 languages including Arabic, Bahasa Indonesia, Bahasa Malaysian, Chinese, Estonian, Farsi, French, Japanese, Korean, Polish, Portuguese, Russian, Spanish, Thai, Turkish, and Vietnamese. The second edition of this book was released by the ILO/IEA in 2010.

Dr. Meshkati simultaneously received a B.S. in Industrial Engineering and a B.A. in Political Science in 1976, from Sharif (Arya-Meher) University of Technology and Shahid Beheshti University (National University of Iran), respectively; a M.S. in Engineering Management in 1978; and a Ph.D. in Industrial and Systems Engineering in 1983 from USC. He is a Certified Professional Ergonomist.

Curtis M. Oldenburg, Ph.D.

Geological Senior Scientist, Energy Geosciences Division,
Lawrence Berkeley National Laboratory

Curtis Oldenburg is a Senior Scientist, Energy Resources Program Domain Lead, Geologic Carbon Sequestration Program Lead, and Editor in Chief of Greenhouse Gases: Science and Technology. Curt's area of expertise is numerical model development and applications for coupled subsurface flow and transport processes. He has worked in geothermal reservoir modeling, vadose zone hydrology, and compressed gas energy storage. Curt's focus for the last fifteen years has been on geologic carbon sequestration with emphasis on CO2 injection for enhanced gas recovery, and near-surface leakage and seepage including monitoring, detection, and risk-based frameworks for site selection and certification. Curt Oldenburg is a co-author of the textbook entitled Introduction to Carbon Capture and Sequestration.

Scott A. Perfect, Ph.D.

Chief Mechanical Engineer, Engineer Directorate,
Lawrence Livermore National Laboratory

Dr. Perfect is the Chief Mechanical Engineer for the Engineering Directorate at Lawrence Livermore National Laboratory (LLNL). In this role, Dr. Perfect provides leadership ensuring the safety and technical quality of mechanical and related engineering activities conducted throughout the 1600-member Engineering Directorate in support of the Laboratory's diverse missions. Along with the Chief Electronics Engineer, he oversees workforce management and employee development activities within the Engineering Directorate.

Dr. Perfect received his B.S. in Civil Engineering and his M.S. and Ph.D. degrees in Theoretical and Applied Mechanics from the University of Illinois, Urbana-Champaign.

Dr. Perfect began his career at LLNL in 1986 as a member of the Experimental Physics Group, designing hardware, conducting experiments, and performing computational simulations in support of the Defense and Nuclear Technologies Program. After three years in that assignment, he joined the Structural and Applied Mechanics Group where he conducted large-scale nonlinear finite element analyses in support of many projects across the LLNL mission space. His prior leadership assignments are Associate Division Leader for the Defense Technologies Engineering Division and Group Leader for the Structural and Applied Mechanics Group. He has published in the areas of vehicle crashworthiness, nuclear material storage and transportation, magnetic fusion energy, biomechanics of human joints, laser crystal stability, single-crystal plasticity, hydrogen storage, and weapon systems.

Terence Thorn

President, JKM Energy and Environmental Consulting

Terence (Terry) Thorn is a 42-year veteran of the domestic and international natural gas industry and has held a wide variety of senior positions beginning his career as Chairman of Mojave Pipeline Company and President and CEO of Transwestern Pipeline Company. He has worked as an international project developer throughout the world.

As a Chief Environmental Officer, Terry supported Greenfield projects in 14 countries to minimize their environmental impact. He wrote and had adopted company wide Environmental Health and Safety Management Standards and implemented the first environmental management plan for pipeline and power plant construction. In attendance at COP 1 and 2, Terry has remained involved in the climate change discussions where he is focusing on international policies and best practices to control methane emissions.

Residing in Houston, Terry is President of JKM Energy and Environmental Consulting and specializes in project development and management, environmental risk assessment and mitigation, business and policy development, and market analysis. He has done considerable work in the areas of pipeline integrity management systems including audit systems for safety and integrity management programs.

He currently serves as Senior Advisor to the President of the International Gas Union where he helps drive the technical, policy and analytical work product for the 13 Committees and Task Forces with their 1000 members from 91 countries. He also serves on the Advisory Boards for the North American Standards Board where he co-chaired the gas electric harmonization task force, and the University of Texas' Bureau of Economic Geology's Center for Energy Economics where he helped found the Electric Power Research Forum. Terry is also on the Board of Air Alliance Houston which focuses on Houston's greatest air pollution challenges in collaboration with universities, regulators, and partner organizations.

Terry has published numerous articles on energy, risk management and corporate governance and was author of the International Energy Agency's 2007 North American Gas Market Review. As advisor to European gas companies and regulators he co-authored The Natural Gas Transmission Business -a Comparison Between the Interstate US-American and European Situations, Environmental Issues Surrounding Shale Gas Production, The U.S. Experience, A Primer. As a participant in the National Petroleum Council Study Prudent Development: Realizing the Potential of North America›s Abundant Natural Gas and Oil Resources (September 2011), Terry wrote in coordination with the subject team the section on electric gas harmonization, co-authored the chapter on electric generation, and advised on the residential commercial chapter. Most recently he has completed market research projects on electricity markets and gas markets including modeling the US gas markets 2015-2050. Gas Shale Environmental Issues and Challenges was just published by Curtin University in 2015. His most recent papers are «The Bridge to Nowhere: Gas in An All Electric World,» «The Paradigms of Reducing Energy Poverty and Meeting Climate Goals,» and «Making Fossil Fuels Great Again: Initial Thoughts on the Trump Energy Policy.»

Samuel J. Traina, Ph.D.

Vice Chancellor of Research and Economic Development,
University of California, Merced

Dr. Samuel Justin Traina joined the University of California, Merced in July 2002 as the founding director of the Sierra Nevada Research Institute. Prior to beginning his UC Merced duties, Dr. Traina was a professor at Ohio State University.

Dr. Traina received his bachelor's degree in soil resource management and his doctorate in soil chemistry from UC Berkeley, where he also served as a graduate research assistant and graduate teaching assistant. Immediately following, he moved to UC Riverside to conduct postdoctoral research and work as an assistant research soil chemist in the Department of Soil and Environmental Sciences.

In July 2007 Dr. Traina became the Vice Chancellor for Research and Graduate Dean.
As of July 1, 2012 Dr. Traina became solely the Vice Chancellor for Research and Economic Development.

Michael W. Wara, J.D., Ph.D.

Associate Professor, Stanford Law School

An expert on energy and environmental law, Michael Wara's research focuses on climate and electricity policy. Professor Wara's current scholarship lies at the intersection between environmental law, energy law, international relations, atmospheric science, and technology policy.

Professor Wara, JD '06, was formerly a geochemist and climate scientist and has published work on the history of the El Niño/La Niña system and its response to changing climates, especially those warmer than today. The results of his scientific research have been published in premier scientific journals, including Science and Nature.

Professor Wara joined Stanford Law in 2007 as a research fellow in environmental law and as a lecturer in law. Previously, he was an associate in Holland & Knight's Government Practice Group, where his practice focused on climate change, land use, and environmental law.

Professor Wara is a research fellow at the Program in Energy and Sustainable Development in Stanford's Freeman Spogli Institute for International Studies, a Faculty Fellow at the Steyer-Taylor Center for Energy Policy and Finance, and a Center Fellow at the Woods Institute for the Environment.

Appendix D

Report Author Biosketches

- **Scott Backhaus**, Los Alamos National Laboratory
- **Giorgia Bettin**, Sandia National Laboratories
- **Robert J. Budnitz**, Scientific Consulting
- **Eliza D. Czolowski**, PSE Healthy Energy
- **Marcus Daniels**, Los Alamos National Laboratory
- **Mary E. Ewers**, Los Alamos National Laboratory
- **Marc L. Fischer**, Lawrence Berkeley National Laboratory
- **S. Katharine Hammond**, University of California, Berkeley
- **Lee Ann Hill**, PSE Healthy Energy
- **Preston D. Jordan**, Lawrence Berkeley National Laboratory
- **Thomas E. McKone**, Lawrence Berkeley National Laboratory
- **Berne Mosely**, Energy Projects Consulting
- **Kuldeep R. Prasad**, National Institute of Standards and Technology
- **Seth B. C. Shonkoff**, PSE Healthy Energy
- **Tom Tomastik**, ALL Consulting, LLC
- **Rodney Walker**, Walker & Associates Consultancy
- **Max Wei**, Lawrence Berkeley National Laboratory

SCOTT BACKHAUS

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EDUCATION

1997	PHD-PHYSICS University of California, Berkeley, CA
1990	BS-ENGINEERING/PHYSICS University of Nebraska, Lincoln, NE

RESEARCH AND PROFESSIONAL EXPERIENCE

Scott Backhaus received his Ph.D. in Physics in 1997 from the University of California at Berkeley in the area of macroscopic quantum behavior of superfluid 3He and 4He. He is currently the principal investigator for several LANL projects funded by the Office of Electricity in the U.S. Department of Energy, is LANL Program Manager for Office of Electricity and for DHS Critical Infrastructure, and leads LANL's component of the DHS National Infrastructure Simulation and Analysis Group.

CURRENT AND PAST POSITIONS

Since 2015	Principal Investigator, National Infrastructure Simulation and Analysis Center, DHS/OCIA Los Alamos National Laboratory, NM
Since 2015	Program Manager, DHS Critical Infrastructure, Emerging Threats Program Office, Global Security, Los Alamos National Laboratory, NM
Since 2012	Program Manager, DOE Office of Electricity, Science Program Office, Applied Energy, Los Alamos National Laboratory
Since 2012	Principal Investigator, Grid Science Projects DOE/OE, Los Alamos National Laboratory, NM
2010	Principal Investigator, Microgrid Projects. Los Alamos National Laboratory, NM
2003-2015	Technical Staff Member, Condensed Matter and Magnet Science Group, Los Alamos National Laboratory, NM

2000-2002	Reines Fellow, Condensed Matter and Thermal Physics Group, Los Alamos National Laboratory, NM
1998-2000	Director's Funded Postdoctoral Fellow, Condensed Matter and Thermal Physics Group, Los Alamos National Laboratory, NM
1992-1997	Graduate Student Researcher, Department of Physics University of California at Berkeley, CA

HONORS AND AWARDS

2011	Best Paper of the Year, "Quarter-wave pulse tube"–Cyrogenics 2003 MIT Technology Review Top 100 Innovators Under 35
2003	New Horizons Idea Award, World Oil Magazine
2000-2003	Reines Fellow, Los Alamos National Laboratory, NM
1999	R&D 100 Award, Thermo Acoustic Stirling Heat Engine, R&D Magazine
1999	Postdoctoral Publication Prize in Experimental Science, "Thermoacoustic-Stirling Heat Engine", Los Alamos National Laboratory, NM
1998-2000	Director Funded Postdoctoral Fellow, Los Alamos National Laboratory, NM
1994-1997	Graduate Student Researcher Fellowship, NASA
1990-1993	National Science Foundation Graduate Fellowship

GIORGIA BETTIN

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EDUCATION

2007	PHD-MECHANICAL ENGINEERING Massachusetts Institute of Technology, MA
2005	MS-MECHANICAL ENGINEERING Massachusetts Institute of Technology, MA
2002	BS-MECHANICAL ENGINEERING University of California, Berkley, CA

CURRENT AND PAST POSITIONS

Since 2012	Senior Member of Technical Staff, Geoscience Research and Applications Sandia National Laboratories
2007-2010	Research Scientist, Materials and Mechanics group Schlumberger Doll Research
2002-2007	Research Assistant, Institute for Soldier Nanotechnology Massachusetts Institute of Technology

ROBERT J. BUDNITZ

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EDUCATION

1968	PHD-PHYSICS Harvard University, Cambridge, MA
1962	MA-PHYSICS Harvard University, Cambridge, MA
1961	BA-PHYSICS Yale University, New Haven, CT

CURRENT AND PAST POSITIONS

Since 2017	Principle Consultant, Robert J. Budnitz Scientific Consulting
Since 2017	Affiliate (retired), Energy Geosciences Division Lawrence Berkeley National Laboratory, University of California, Berkeley, CA
2007-2017	Staff Scientist, Energy Geosciences Division Lawrence Berkeley National Laboratory, University of California, Berkeley, CA
2004-2007	Leader, Nuclear and Risk Science Group, Energy and Environment Directorate Program Leader for Nuclear Systems Safety and Security, E&E Directorate Lawrence Livermore National Laboratory, University of California, Livermore, CA
2002-2004	Responsible for the Science & Technology Program, DOE Yucca Mountain Project at the US Department of Energy, Washington D.C. Lawrence Livermore National Laboratory, University of California, Livermore, CA
1981-2002	President, Future Resources Associates, Inc., Berkeley, CA
1980-1981	Vice President and Director, Energy and Environmental Technologies Division Teknekron, Inc., Berkeley, CA

1978-1980	Deputy Director and Director, Office of Nuclear Regulatory Research U.S. Nuclear Regulatory Commission, Washington D.C.
1967-1980	Associate Director of LBL and Head, Energy & Environment Division Program Leader, LBL Environmental Research Program Physicist, LBL Environmental Research Program Post-Doctoral Physicist, LBL High-Energy Physics Program Lawrence Berkeley National Laboratory, University of California, Berkeley, CA

HONORS AND AWARDS

2017	Elected member, U.S. National Academy of Engineering
2007	Elected Fellow, American Association for the Advancement of Science
2006	American Nuclear Society, Standards Service Award
2005	American Nuclear Society, Theos J. Thompson Award for Reactor Safety
2002	Selected National Associate, U.S. National Academy of Sciences
2001	Society for Risk Analysis, "Outstanding Risk Practitioner Award for 2001"
1998	Elected Fellow, American Nuclear Society
1996	Elected Fellow, Society for Risk Analysis
1988	Elected Fellow, American Physical Society
1988	American Nuclear Society, Nuclear Reactor Safety Division "Best Paper Award"
1961	National Science Foundation Graduate Fellowship in Physics

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EDUCATION

2013	MS-PROFESSIONAL STUDIES IN ENVIRONMENTAL SCIENCE SUNY College of Environmental Science and Forestry, Syracuse, NY
2009	BS-ENVIRONMENTAL SCIENCE Allegheny College, Meadville, PA

CURRENT AND PAST POSITIONS

Since 2015	Program Associate, Energy-Environment Program PSE Healthy Energy, Ithaca, NY
2012-2015	Scientist 1 / Graphics Area Lead GZA Geoenvironmental Inc., East Syracuse, NY
2011-2012	GIS Specialist The Palmerton Group, LCC, East Syracuse, NY
2009-2010	Research Scientist, accuracy assessment of land use change maps, water quality Geographic Modeling Services, Jamesville, NY

MARCUS DANIELS

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EDUCATION

1996	SYSTEM SCIENCE, PSU
1994	PSYCHOLOGY, PSU

CURRENT AND PAST POSITIONS

Since 2015	Molecular Dynamics, Exploratory Research Program Los Alamos National Laboratory, NM
Since 2016	National Infrastructure Simulation and Anlaysis Center Los Alamos National Laboratory, NM
Since 2015	Quantum Computation, Directed Research Program Los Alamos National Laboratory, NM
2013-2014	ASC Verification and Validation Los Alamos National Laboratory, NM
Since 2012	Promoted Scientist 3, ASC Eulerian codes Los Alamos National Laboratory, NM
2010-2012	Promoted Scientist 2, Programming Models Team Los Alamos National Laboratory, NM
2005-2010	Research Technologist 3, Theoretical Biology Los Alamos National Laboratory, NM
2004-2006	Consulting Modeler, US Department of Agriculture
2001-2005	Modeler, Markets Evolution Research Group Santa Fe Institute, NM
1996-1999	Lead Developer Swarm Program, Executive Director Swarm Developer Group Santa Fe Institute, NM

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EDUCATION

2004	PHD-ECONOMICS University of New Mexico, Albuquerque, NM
2002	MA-ECONOMICS University of New Mexico, Albuquerque, NM
1987	BA-ECONOMICS University of California, Santa Barbara, CA

CURRENT AND PAST POSITIONS

Since 2004	Scientist 3, 2, 1, National Infrastructure Simulation and Analysis Center (NISAC) PI Global Oil and Natural Gas Capability Development Los Alamos National Laboratory, NM
2001-2004	Teaching and Research Assistant University of New Mexico, NM

HONORS AND AWARDS

2015	LANL Awards Program in recognition of excellent performance and commitment to the NISAC Fast Response Team
2002	J. Raymond Stuart Prize in Economics, University of New Mexico, NM

MARC L. FISCHER

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Environmental Energy Technologies Division
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EDUCATION

1991	PHD-PHYSICS University of California, Berkeley, CA
1982	MS-PHYSICS University of Illinois at Urbana-Champaign, IL
1981	BS-PHYSICS Massachusetts Institute of Technology, MA

CURRENT AND PAST POSITIONS

Since 1998	Staff Scientist, Lawrence Berkeley National Laboratory, Berkeley, CA
1995-1997	Assistant Research Scientist, Environmental Science and Policy Program, University of California, Berkeley, CA
1993-1995.	Postdoctoral Fellow, Lawrence Berkeley National Laboratory, Berkeley, CA
1991-1993	Postdoctoral Fellow, Department of Physics, University of California, Berkeley, CA

HONORS AND AWARDS

1987-1990	NASA Graduate Student Research Fellow
1983	Berkeley University Fellow

S. KATHARINE HAMMOND

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EDUCATION

1981	MS-ENVIRONMENTAL HEALTH SCIENCES Harvard School of Public Health, MA
1976	PHD-CHEMSITRY Brandeis University, MA
1971	BA-CHEMISTRY Oberlin College, OH

CURRENT AND PAST POSITIONS

Since 2016	Associate Dean for Academic Affairs, School of Public Health, University of California, Berkeley, CA
Since 1994	Professor of Environmental Health Sciences (Associate Professor 1994-2000), School of Public Health, University of California, Berkeley, CA
Since 2013 1994-2001	Director, Industrial Hygiene Program, University of California, Berkeley, CA
2014-2017	Co-Chair, Graduate Group in Environmental Health Sciences, University of California, Berkeley, CA
2006-2012	Chair, Environmental Health Sciences Division, School of Public Health, University of California, Berkeley, CA
1998-2006	Chair, Graduate Group in Environmental Health Sciences, University of California, Berkeley, CA
1985-1994	Associate Professor of Family and Community Medicine and of Pharmacology (Assistant Professor 1985-1989; tenured in April, 1993), University of Massachusetts Medical Center Worcester, MA
1993-1994	Director, Environmental Health Division, Department of Family and Community, Medicine, University of Massachusetts Medical Center Worcester, MA

1985-2003	Visiting Lecturer on Industrial Hygiene; Harvard School of Public Health, Boston, MA
1981-1984	Research Associate, Industrial Hygiene, Harvard School of Public Health, Boston, MA
1976-1980	Assistant Professor of Chemistry, Wheaton College, Norton, MA

HONORS AND AWARDS

2013-2017	School of Public Health Committee on Teaching Excellence Award
2008	Henry F. Smyth Award, Academy of Industrial Hygiene, American Industrial Hygiene Association
2008	Dr. William Cahan Distinguished Professor Award, Flight Attendants Medical Research Institute
2005	Alfred W. Childs Distinguished Service Award, U of CA, Berkeley, School of Public Health
2004	Rachel Carson Environmental Award, American Industrial Hygiene Association
2002	Fellow, American Industrial Hygiene Association
1999	Alice Hamilton Award for Excellence in Occupational Safety and Health, NIOSH

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EDUCATION

2016	MS-PUBLIC HEALTH, ENVIRONMENTAL HEALTH SCIENCES University of California, Berkeley, CA
2013	BS-ENVIRONMENTAL SCIENCE Ithaca College, Ithaca, NY

CURRENT AND PAST POSITIONS

Since 2016	Associate, Environmental Health Program PSE Healthy Energy, Oakland, CA
2016	Research Assistant Office of Environmental Health Hazard Assessment, Oakland, CA
2015	Health Intern Natural Resources Defense Council, San Francisco, CA
2014	Environmental Laboratory Intern Ithaca Area Wastewater Treatment Facility, Ithaca, NY
2013	Water Quality Intern City of Ithaca Water Treatment Plant, Ithaca, NY
2013	Environmental Health Intern Tompkins County Health Department, Ithaca, NY

PRESTON D. JORDAN

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EDUCATION

1997	MS-GEOTECHNICAL ENGINEERING University of California, Berkeley, CA
1988	BA-GEOLOGY University of California, Berkeley, CA

CURRENT AND PAST POSITIONS

Since 2017	Principal Scientific Engineering Associate, Energy Geosciences Division Lawrence Berkeley National Laboratory, CA
2010-2017	Staff Research Associate, Energy Geosciences Division Lawrence Berkeley National Laboratory, CA
1998-2010	Principal Research Associate, Earth Science Division Lawrence Berkeley National Laboratory, CA
1995-1998	Senior Research Associate, Earth Science Division Lawrence Berkeley National Laboratory, CA
1994-1995	Research Associate, Earth Science Division Lawrence Berkeley National Laboratory, CA
1990-1994	Research Technician, Earth Science Division Lawrence Berkeley National Laboratory, CA
1989-1990	Field Geologist, Consultant to the United States Department of Justice

AWARDS

2016	Societal Impact for the Aliso Canyon natural gas storage well blowout response, Lawrence Berkeley National Laboratory
2015	Spot for the SB4 well stimulation study, Lawrence Berkeley National Laboratory

2014	Spot for the BLM CA hydraulic fracturing study, Lawrence Berkeley National Laboratory
2012	Outstanding Mentor, Lawrence Berkeley National Laboratory
2010	Outstanding Performance for community relations, Lawrence Berkeley National Laboratory

THOMAS E. MCKONE

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EDUCATION

1981	PHD-ENGINEERING University of California, Los Angeles, CA
1977	MS-ENGINEERING University of California, Los Angeles, CA
1974	BA-CHEMISTRY St. Thomas College, St. Paul, MN

CURRENT AND PAST POSITIONS

Since 2015	Affiliated Faculty School of Public Health, University of California, Berkeley, CA
Since 2011	Senior Scientist and Deputy for Research Programs Energy Analysis and Environmental Impacts Division, Lawrence Berkeley National Laboratory, Berkeley, CA
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HONORS AND AWARDS

2008	Jerome J. Wesolowski Award, International Society of Exposure Science
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HONORS AND AWARDS

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HONORS AND AWARDS

2017	Pioneer Under 40 in Environmental Public Health, Collaborative on Health and the Environment (CHE)
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EDUCATION

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1988-2014	Senior Geologist -Ohio Department of Natural Resources, Division of Oil and Gas Resources Management, Columbus, OH
1982-1988	Consulting Geologist - Involved in exploration, development, and production of oil and gas wells in Ohio.

HONORS AND AWARDS

2017	Certified Petroleum Geologist # 6354 – American Association of Petroleum Geologists
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2002-2006	Executive Vice President-Engineering Diversified Energy Services, Inc., Atlanta, GA
2001-2002	Natural Gas Director City of Toccoa, GA
1999-2001	Public Works Director City of Hartwell, GA
1985-1999	Various Positions (Corporate Engineer, Design Engineer/Drafting Supervisor, Engineering Supervisor, GIS Program Manager, Region Design Engineer) Atlanta Gas Light Company, GA

HONORS AND AWARDS

2012	American Public Gas Association (APGA) Harry M. Cooke Award for Distinguished Service to Natural Gas Industry

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2002-2007	Process Integration Manager Intel Corporation, Santa Clara, CA

Appendix E

Full List of all Report Findings, Conclusions, and Recommendations

Key Question 1

What risks do California's underground gas storage facilities pose to health, safety, environment and infrastructure?

1.1 CHARACTERISTICS OF CALIFORNIA UNDERGROUND GAS STORAGE FACILITIES

Data Quality in DOGGR's Public Datasets

Finding: Information regarding quality control for public datasets relevant to underground gas storage is not available. Aspects of the data suggest quality control processes are not uniformly applied. For instance, well API# 03700722 has high casing and zero tubing pressures at times when its configuration suggests this is not possible. It also has the same casing pressure reported to four significant figures monthly from August 2008 through April 2009. While there appears to be sufficient consistency within the data to provide for accurate characterization of gas storage across the state, the narrower the focus, such as upon a single well, the less accurate the data can be presumed. This can interfere with understanding the risk of events at particular wells and other facilities of interest. As another example of data inconsistencies, some data regarding the same feature varies between publicly available datasets. For instance, well API #03714015 is in the Del Rey Hills area of the Playa del Rey field, which has gas storage, in DOGGR's production and injection database, but is in the Venice area, which does not have gas storage, in DOGGR's AllWells file. The uncertainty created by such inconsistencies has various implications—for instance, whether this well accesses the gas storage reservoir or not affects the LOC risk of that storage. As with the previous finding, though, these inconsistencies do not appear to be sufficiently frequent to preclude accurate characterization of UGS in California.

Conclusion: While DOGGR's public databases provide a wealth of information on underground gas storage wells, this study finds that there are various obvious inconsistencies between and apparent inaccuracies within these databases, which suggests that either quality control processes do not exist or are not uniformly applied. We could not find information regarding quality control for these public data sets relevant to underground gas storage. (See Conclusion 1.21 in the Summary Report.)

Recommendation: The Steering Committee recommends that quality control plans need to be made available if they exist, or need to be created if they do not exist. DOGGR needs to check for consistency between data sets and correct inconsistencies. In the longer-term, DOGGR should develop a unified data source from which all public data products are produced. (See Recommendation 1.21 in the Summary Report.)

<u>Storage in Depleted Oil Versus Gas Reservoirs and Independent Versus Utility Operated</u>

Finding: Storage in depleted gas reservoirs (primarily in northern California) differs from storage in depleted oil reservoirs (only in southern California) in a variety of ways, including:

- Well age and orientation
- Wellhead distribution
- Reservoir depth, initial pressure, and temperature
- Reservoir operating pressure relative to initial pressure
- Compounds in produced gas

Storage by independent operators differs from storage by PG&E, both in depleted gas reservoirs, in a variety of ways, including:

- Well age
- Interconnect length per capacity and gas transferred
- Location of gas handling plant relative to wells

Conclusion: The systematic physical and operational differences between storage in depleted oil and gas reservoirs, independent versus utility operated in depleted gas reservoirs as practiced, may result in significantly different risk profiles between these types of storage fields.

Recommendation: Characterize gas storage risk in depleted oil versus gas reservoirs, and independent versus utility operated in depleted gas reservoirs, to determine if there are generic differences, such as by simulating well blowouts for each. Identification of such differences might lead to different mitigation approaches in each setting, and identify practices that could be transferred between settings.

Age of Storage Wells in Southern California

Finding: Almost two thirds of the wells used for storage in southern California were spudded six to nine decades ago. Two fifths of stored gas was transferred via these wells.

Conclusion: There does not appear to be any limit on the age of well components used for gas storage in the state.

Recommendation: Determine the reasonable life expectancy of a well component given its operation and maintenance, and determine a monitoring and testing schedule that varies based on the temporal failure rate distribution of that type of component.

1.2 FAILURE MODES, LIKELIHOOD, AND CONSEQUENCES

Overall Failure Frequency of UGS

Finding: Gas storage has been carried out in California for over 60 years at around 20 different sites. Several of the facilities have had serious LOC incidents. The most problematic of these sites have been closed and are no longer storing gas. Of the 12 sites open today, seven have incidents recorded in the literature. Although possibly artifacts of reporting or the fact that California's larger facilities are larger than the worldwide average, the failure rate of UGS in California appears to be higher than the worldwide failure frequency, which is about the same or lower than the failure frequency of oil and gas extraction operations.

Conclusion: Analysis of historic failure-rate statistics of California's underground gas storage facilities points to a need for better risk management and improvement in regulations and practices. The Steering Committee views the new regulations proposed by DOGGR as a major step forward to reduce the risk of underground gas storage facilities, provided they are consistently and thoroughly applied and enforced across all storage facilities. In the future, careful re-evaluation of failure statistics, based on ongoing reporting and evaluation of incidents, can help determine whether and to what degree incident reductions have indeed been realized. (See Conclusion 1.1 in the Summary Report).

Recommendation: At regular intervals in the future, DOGGR should assess—by re-analyzing incident reports—whether the frequency of underground gas storage loss-of-containment incidents and other underground gas storage failures in California has actually been reduced. DOGGR should use these statistics to inform auditing processes for regulatory effectiveness. (See Recommendation 1.1 in the Summary Report.)

Focus on Subsurface

Finding: Queries of the database compilations of UGS incidents in California show that well-related leakage is by far the most common failure mode for LOC incidents in this state. In contrast, compilations of UGS failures worldwide suggest that LOC incidents at UGS facilities worldwide are four times more likely to involve above-ground infrastructure (valves, pipes, wellheads, compressors, and other systems) as compared to incidents involving wells. It appears that California's subsurface LOC incidents are substantially higher than the worldwide average.

Conclusion: Although efforts to reduce loss-of-containment incidents should be expended on both surface and subsurface parts of the underground gas storage systems in California, there appears to be a large opportunity to reduce loss-of-containment risk by focusing on reducing subsurface integrity failures, in particular with regard to well integrity issues. Emphasis on subsurface failure modes is consistent with the focus of many of the requirements in DOGGR's interim and draft final regulations. (See Conclusion 1.2 in the Summary Report).

Require Tubing and Packer

Finding: In California, DOGGR regulates UGS wells and until now has not required the use of tubing and packer (two-point failure requirement) in UGS wells. Although this is how most UGS wells are operated in the U.S., it is inconsistent with the U.S. EPA's UIC program, which generally requires injection wells to utilize a tubing and packer configuration. But because UGS is specifically excluded from the UIC program, no such federal requirement exists. The new proposed DOGGR regulations, planned to take effect January 1, 2018, will require a two-point failure configuration for all UGS wells. By the exclusion of UGS from the UIC program, UGS wells have not been required to conform to the two-point failure requirement, resulting in widespread operation of UGS wells that produce and inject fluid through the A-annulus, with the casing serving as the only barrier between high-pressure gas and the environment, including along regions of casing without cement between the outside of casing and the borehole wall. If the SS-25 well at Aliso Canyon had been operated using tubing and packer for production and injection, the hole in the casing, suspected to have been caused by corrosion, would not have caused gas to escape to surface in the 2015 Aliso Canyon incident, because there would have been no reservoir pressure support and gas supply to the A-annulus to feed an ongoing blowout (major LOC incident).

Conclusion: The Steering Committee views the requirement in the new DOGGR regulations of a two-point failure configuration for all underground gas storage wells as an important step in preventing major well blowouts and low-flow-rate loss-of-containment events. (See Conclusion 1.3 in the Summary Report.)

Risk Assessment of Failure Scenarios

Finding: Compilations of UGS incidents worldwide and in California show that loss-of-containment (LOC) of high-pressure natural gas at UGS facilities often occurs by a chain of events that can be described by a failure scenario, which often involves human and organizational factors (HOFs). Queries of the updated database of Evans and Schultz (2017) show that well-related leakage is by far the most common failure mode for LOC incidents in California.

Conclusion: Failure scenarios involving initiating and multiple contributing events are common experience. Risk assessment and analysis methods and capabilities are well-developed and available from the engineering consulting industry to address failure scenarios in terms of understanding linkages between events, finding mitigating actions, and quantifying likelihood and assessing risk quantitatively and semi-quantitatively.

Recommendation: Operators of UGS facilities should utilize long experience and new and existing data to carry out quantitative risk assessment (what is the risk?) and risk analysis (what are the main sources of risk? How can risk be reduced?).

<u>Basis for Failure Frequency Estimates</u>

Finding: Different authors use a different denominator or basis for estimating failure frequency. E.g., some calculate failure rate on a per well basis, while others use per well-yr or per facility-yr.

Conclusion: The number of wells in use at any time over the course of operations of UGS facilities changes. Furthermore, there are abandoned wells that can be an issue for integrity but that are not used for storage. These facts make it difficult to form a meaningful metric for failure frequency using wells as the basis. We prefer to base failure frequencies on a per facility-yr basis. To rank sites and account for the larger number of wells at some sites, we suggest using a working-gas-capacity (Bcf) normalization, whereby the per facility-yr frequency is multiplied by the ratio of the California-average working gas capacity to the particular site working gas capacity. By this approach, one can account indirectly for the expected larger number of wells at larger sites, and normalize failure frequency to the average size site.

<u>Natural Hazards Can Affect Integrity of UGS Facilities</u>

Finding: Some California UGS facilities are located in regions with particular hazards that can affect UGS infrastructure, among which are seismic, landslide, flood, tsunami, and wildfire hazards. The risk arising from these hazards along with monitoring, prevention, and intervention needs, is now being assessed in the risk management plans that DOGGR now requires from each facility. Some natural hazards are more easily evaluated and mitigated than others; e.g., facilities potentially affected by periodic flooding are often protected by dams or placed on elevated land. Earthquake risk, on the other hand, is harder to assess and mitigate. Fault displacement and seismic ground motion can directly affect the surface infrastructure. Fault displacement can also affect wells at depth through shearing of the well casing if the well crosses the plane of the fault. Earthquake risk is a concern in several California facilities, such as Aliso Canyon, Honor Rancho, and Playa del Rey. SoCalGas is currently conducting an in-depth analysis of the risk related to the Santa Susana Fault, including a probabilistic seismic hazard analysis and a probabilistic fault displacement analysis.

Conclusion: Natural hazards can significantly affect the integrity of underground gas storage facilities. (See Conclusion 1.4 in the Summary Report.)

Recommendation: Regulators need to ensure that the risk management plans and risk assessments required as part of the new DOGGR regulations focus on all relevant natural hazards at each facility. In-depth site-specific technical or geological studies may be needed to evaluate potential natural hazards associated with underground gas storage facilities. For some facilities, earthquake risks fall under that category. (See Recommendation 1.4a in the Summary Report.)

Recommendation: Agencies with jurisdiction should ensure that earthquake risks (and other relevant natural hazards) are specifically investigated with in-depth technical or geological studies at all facilities where risk management plans suggest elevated hazard. (See Recommendation 1.4b in the Summary Report.)

<u>Protect UGS from Attack</u>

Finding: By analogy with oil and gas pipelines and wells, which have been the subject of numerous terrorist incidents around the world, UGS facilities in California are vulnerable to similar kinds of attacks.

Conclusion: It is well known that UGS facilities store a highly energetic fuel at high pressure, and that high-pressure pipelines of natural gas are ubiquitous at UGS sites. High-pressure pipelines of natural gas provide a source for explosion and re that may make UGS sites attractive to terrorists or other groups or individuals intent on harm.

Recommendation: UGS sites should carry out a top-to-bottom review of mitigation of the threat of terrorism or other attacks by individuals or groups. Examples of mitigations of this threat include increasing security, decreasing the attractiveness of the facility as a target, maintaining an appropriate degree of confidentiality about operations, improving cyber security to avoid hacking attacks, and locking key valves and controls.

<u>Better Emissions Data and On-site Meteorological Stations</u>

Finding: UGS sites in California are not uniformly equipped with meteorological stations or gas monitoring equipment. Bottom-up approaches that employ empirical emission factors are used to estimate emission inventories. These approaches do not provide the spatially and temporally varying emission data that are critical for estimating downwind consequences of leaks from individual UGS sites.

NOAA's Integrated Surface Database (ISD) provides meteorological data; however, the distances between California UGS sites and the closest stations can range from 2 to 25 km. Many UGS facilities are located in an area of complex topography, which can make the available meteorological data unreliable.

Conclusion: Although a range of practical and sophisticated modeling capabilities is readily available, lack of temporal and spatially varying emission data as well as reliable meteorological data make it difficult to accurately estimate the concentrations and dispersion of gas leakage from UGS facilities.

Recommendation: A practical implementation of continuous emission monitoring technology should be deployed at each UGS facility to provide reliable spatially and temporally varying data for analysis. On-site weather stations should be installed at each UGS facility following National Weather Service (NWS) guidelines. These data could be used to generate accurate estimates of dispersion of leaking gases for risk assessment and emergency response purposes using readily available dispersion models.

Risk to UGS Infrastructure from Fire and Explosions

Finding: Large accidental leaks of natural gas can pose a significant threat to people and property due to thermal radiation from sustained res and collapse of buildings and infrastructure from explosions. Decompression cooling can cause small pipeline leaks to turn into large leaks. Horizontal jet dispersion models that characterize the concentration profile and re models that characterize the radiative heat flux can estimate the ground area (hazard zone) affected by credible failure scenarios. Leak rates and meteorological data can be combined with flammability/explosion-limit estimates to delineate the extent of the hazard zone for risk assessment purposes.

Conclusion: The size of fire and explosion hazard zones can be larger than the footprints of local surface infrastructure, e.g., a compressor pad, gas-processing facility pad, or the clustered wellheads on pads of multiple deviated wells. This is especially true for facilities with gas processing equipment co-located with office/control facilities. LOC failure impacts to UGS infrastructure are potentially very large.

Recommendation: Hazard zones should be delineated for each UGS facility to focus risk mitigation on elimination of leakage and ignition sources to reduce the likelihood of re and explosion, and to design surface infrastructure (e.g., buildings and their layout) to reduce the consequences (loss prevention) of re and explosion if they should occur (safer site-use planning).

Impacts of Leakage on USDW

Finding: Stray gas migration from oil and gas operations into USDW has been well documented across the United States. Leakage of natural gas into USDW from UGS operations can occur and typically is caused by the phenomenon called "annular over pressurization." Most UGS wells are constructed in a manner that results in an open annular space behind the production casing. This annulus is a potential avenue for gas migration from the gas storage reservoir of higher hydrodynamic pressure into formations of lower hydrodynamic pressure, including aquifers.

Conclusion: Storage gas migration into USDW in California has occurred and has been documented in association with the Playa del Rey gas storage field. Other gas storage migration incidents into USDW may go undocumented due to the lack of groundwater monitoring wells or lack of reliance on domestic water wells for private water supplies that would detect the presence of stray gas. Storage gas migration to the surface in a number of California gas storage fields has occurred through leakage through faults and abandoned or improperly plugged oil and gas wells (e.g., Honor Rancho and Montebello).

Recommendation: Implement the proposed DOGGR regulations to improve well integrity and require groundwater monitoring wells at UGS sites to detect possible stray gas migration to USDW aquifers.

Clustered vs. Dispersed Wells

Finding: UGS facilities developed in California depleted oil (DO) reservoirs utilize mostly vertical wells that are widely dispersed across the field. In contrast, UGS facilities developed in California depleted gas (DG) reservoirs are often deviated with closely spaced and centralized wellheads.

Conclusion: There are tradeoffs in risk management of closely spaced versus dispersed wellheads. Maintenance and observation of the wellheads is facilitated by clustering, but failure of a wellhead (e.g., a burning blowout) in close proximity to other wellheads can lead to multiple wellhead failures.

1.3 CAPACITY OF UGS SITES: EFFECTS OF AGE AND STORAGE INTEGRITY

Addressing Formation Damage

Finding: The gas storage reservoir and its ability to deliver gas can be altered due to formation compaction and damage from long-term oil, produced water, and natural gas extraction resulting from grain alteration, changes to reservoir pressure conditions, and changes to the fluid contacts within the underground gas storage field. Formation damage causes reduction in gas storage reservoir permeability which leads to a decrease in deliverability that dramatically impacts the effective capacity of the underground gas storage field.

Conclusion: Because formation damage is more likely in older wells with long histories of production, UGS capacity can be affected by the age of the wells at the UGS facility and its history of operations.

Recommendation: Operators should carry out proactive approaches to identifying, addressing, and properly mitigating formation damage in advance of the reduction in formation permeability to avoid loss of UGS reservoir capacity. Being aware of formation damage implications during drilling, completion, injection, and production operations can help in substantially reducing formation damage and enhancing the ability of a well to inject and withdraw storage gas.

Need for Stronger Regulations to Avoid Loss of Storage Capacity

Finding: Loss of reservoir integrity is a failure of UGS that results in closing of UGS reservoirs, or shutting in of certain wells, or requirement to operate at lower pressure. California UGS has experienced multiple LOC incidents due to reservoir integrity failure, which resulted in storage gas migration through old oil and gas wells back to the surface.

Conclusion: Gas storage reservoir integrity can be defined by the geological and geomechanical conditions that are present within the reservoir that allow for safe operations beyond the wellbore. Likely avenues for gas migration from the reservoir are caused by failure of vertical and/or lateral containment, which can be caused by artificial (well) penetrations, naturally occurring faults or fracture systems that may be transmissive, compromising of the confining zone/caprock sequence due to reservoir overpressurization, and overfilling of the structural or stratigraphic geologic spill points. Fundamentally, UGS reservoir integrity carries two different types of risks: the release of gas from the storage reservoir that reaches aquifers and/ or the surface, or migration of storage gas from the reservoir into overlying or adjacent geologic formations, where it becomes nonrecoverable.

Recommendation: More stringent underground gas storage regulations should be developed to require more technical, geologic, and engineering data to better characterize the gas storage reservoir. By assessing gas-storage-reservoir integrity using a holistic approach (i.e., utilizing multiple approaches such as geophysical logging and pressure testing), the number of incidents associated with gas-storage-reservoir-integrity failure can be dramatically reduced with the added benefit of avoiding loss of storage capacity.

1.4 HUMAN HEALTH HAZARDS, RISKS, AND IMPACTS ASSOCIATED WITH UNDERGROUND GAS STORAGE IN CALIFORNIA

Emissions Inventory Information Gaps and Uncertainty

Finding: There are a number of human health hazards associated with UGS in California that can be predominantly attributable to exposure to toxic air pollutants. These toxic compounds emitted during routine and off-normal emissions scenarios include but are not limited to odorants, compressor combustion emissions, benzene, toluene, and other potentially toxic chemicals extracted from residual oil in depleted oil reservoirs. Given the limited number of compounds monitored for during the 2015 Aliso Canyon incident compared to the number of compounds reported to the California Air Resources Board as emitted from UGS facilities, there is significant uncertainty as to the human health risks and impacts of this large LOC event both over the short- and long-term. Our repeated attempts to acquire useful information about gas composition at each UGS facility in California were unsuccessful. Working with the CPUC, we made formal requests to all operators seeking information on the chemical composition of the stored gas. All responded, but none could provide the detailed information we needed (See Appendix 1.D, in Chapter 1).

Conclusion: Because emissions inventories for underground gas storage facilities lack the temporal, spatial, and technology-specific detail as well as verifiability of emission types and rates, currently available emissions inventories cannot support quantitative human exposure or health risk assessments. There is a need to identify the chemical composition of the gas that is stored, withdrawn, stripped, and delivered to the pipeline, so that associated hazards during routine and off-normal emission scenarios can be assessed. (See Conclusion 1.5 in the Summary Report.)

Recommendation: Agencies with jurisdiction should require that underground gas storage facility operators provide detailed gas composition information at appropriate time intervals. Additionally, these agencies should require the development of a comprehensive chemical inventory of all chemicals stored and used on-site, and the chemical composition of stored, withdrawn, stripped, and compressed gas for each underground gas storage facility. These data should be used to prioritize chemicals to enable site operators and local first responders to set health-based goals for monitoring and risk assessment actions. (See Recommendation 1.5 in the Summary Report.)

<u>Health Symptoms in Communities Near the 2015 Aliso Canyon Incident Were Attributed to the Aliso Canyon UGS Facility</u>

Finding: The majority of households near the Aliso Canyon UGS facility experienced health symptoms during the SS-25 blowout and after the well was sealed, and these symptoms were likely related to the gas leak and/or other emission sources from the Aliso Canyon UGS facility. While many of the symptoms reported by residents match the symptom profile of exposure to mercaptans (gas odorants), other symptoms such as nosebleeds do not, suggesting that air pollutant and other environmental monitoring was not sufficiently inclusive of potential health-damaging pollutants.

Conclusion: Emissions from the 2015 Aliso Canyon incident were likely responsible for widespread health symptoms in the nearby Porter Ranch population. These types of population health impacts should be expected from any large-scale natural gas releases from any underground gas storage facility, especially those located near areas of high population density. However, many of the specific exposures that caused these symptoms remain uncertain, due to incomplete information about the composition of the air pollutant emissions and their downwind concentrations. (See Conclusion 1.6a in the Summary Report.)

Recommendation: Community health risks should be a primary component of risk management plans and best management practices for emission reductions, and measures to avoid (normal and off-normal) gas releases should be immediately implemented at existing underground gas storage facilities. In addition, options for public health surveillance should be considered both during and following major loss-of-containment events to identify adverse health effects in communities. (See Recommendation 1.6a in the Summary Report.)

<u>Population Exposures to Toxic Air Pollutants Increase with Higher Emissions, Closer Community Proximity and Higher Population Density</u>

Finding: Approximately 1.85 million residents live within five miles of UGS facilities in the State of California. In the absence of reliable information on emissions inventories and expected release rates, potential health hazards can be evaluated using normalized source-receptor relationships obtained from atmospheric transport models and best estimates of population distance and density. Both concentration/source and population-intake/source ratios (intake fraction) provide helpful tools to assess the variability of potential exposures and risks among different UGS facilities.

Conclusion: Underground gas storage facilities pose more elevated health risks when located in areas of high population density, such as the Los Angeles Basin, because of the larger numbers of people nearby that can be exposed to toxic air pollutants. Emissions from underground gas storage facilities, especially during large loss-of-containment events, can present health hazards to nearby communities in California. Many of the constituents potentially emitted by underground gas storage facilities can damage health and place disproportionate risks on sensitive populations, including children, pregnant women, the elderly, and those with pre-existing respiratory and cardiovascular conditions. (See Conclusion 1.7 in the Summary Report.)

Recommendation: Regulators need to ensure that the risk management plans required as part of the new DOGGR regulations take into account the population density near and proximity to underground gas storage facilities. One mitigating approach to reduce risks to nearby population centers could be to define minimum health-based and fire-safety-based surface setback distances between facilities and human populations, informed by available science and results from facility-specific risk assessment studies. This may be most feasible for future zoning decisions and new facility or community construction projects. Such setbacks would ensure that people located in and around various classes of buildings such as residences, schools, hospitals, and senior care facilities are located at a safe distance from underground gas storage facilities during normal and off-normal emission events. (See Recommendation 1.7 in the Summary Report.)

Occupational Health and Safety Considerations

Finding: Based on toxic chemicals known to be present on-site, and publicly available emission reporting to air regulators under the Air Toxics Hot Spots Program, we have identified toxic chemicals used at and emitted from UGS facilities. These chemicals include, but are not limited to, hydrogen sulfide, benzene, acrolein, formaldehyde, and 1,3 Butadiene. Currently we have found no available quantitative exposure measurements.

Conclusion: Workers at underground gas storage facilities are likely exposed to toxic chemicals, but the actual extent of those exposures is not known. Without quantitative emission and exposure measurements, we cannot assess the impact of these exposures on workers' health. (See Conclusion 1.8 in the Summary Report.)

Recommendation: Underground gas storage facilities should make quantitative data on emissions of, and worker exposures to, toxic chemicals from facility operations available to the public and to agencies of jurisdiction—e.g., California Occupational Safety and Health Administration (CalOSHA), California Public Utilities Commission (CPUC)—to enable robust risk assessments. It may be advisable to require that underground gas storage facilities be subject to the Process Safety Management of Highly Hazardous Chemicals Standard (29 CFR 1910.119), which contains requirements for the management of hazards associated with processes using highly hazardous chemicals. (See Recommendation 1.8a in the Summary Report.)

Recommendation: The State should require that underground gas storage workplaces conform to requirements of CalOSHA and federal OSHA, and impose additional requirements to protect the health and safety of on-site workers (employees, temporary workers and contractors), whether or not they are legally bound to comply. These requirements include that (1) all training and preparation for incidents and releases be fully concordant with best practices (see Appendix 1.G in Chapter 1); (2) all safety equipment be fully operational and up to date, readily available, and all workers trained in equipment location and proper use; (3) all incident commanders be provided with sufficient, current training; (4) all health and safety standards be observed for all workers on site; and (5) air sampling of workers' exposures be required during routine and off-normal operations to ensure that exposures are within the most health-protective occupational exposure limits. (See Recommendation 1.8b in the Summary Report.)

Continuous Facility Air-Quality Monitoring

Finding: Many UGS facilities emit multiple health-damaging air pollutants during routine operations. Available emissions inventories suggest that the most commonly emitted air pollutants associated with UGS by mass include nitrogen oxides, carbon monoxide, particulate matter, ammonia, and formaldehyde. For instance, Aliso Canyon is the single largest emitter of formaldehyde in the South Coast Air Quality Management District. Gas-powered (as compared to electric-powered) compressor stations are associated with the highest continuous emissions of formaldehyde. CARB regulations for underground gas storage facilities in place since October 1, 2017 require continuous methane concentration monitoring at facility upwind and downwind locations (at least one pair of upwind and downwind locations) but without air sampling.

Conclusion: There is a need to track and if necessary reduce emissions of toxic air pollutants from underground gas storage facilities during routine operations. (See Conclusion 1.9 in the Summary Report.)

Recommendation: Agencies with jurisdiction should require actions to reduce exposure of on-site workers and nearby populations to toxic air pollutants, other health-damaging air pollutants emitted from underground gas storage facilities during routine operations, and ground level ozone, nitrogen oxides, and other ozone precursors. These steps could include (1) the implementation of air monitors within the facilities and at the fence line or other appropriate locations—preferably with continuous methane monitoring with trigger sampling to quickly deploy appropriate off-site air quality monitoring networks during incidents; (2) the increased application and enforcement of emission control technologies to limit air pollutant emissions; (3) the replacement of gas-powered compressors with electric-powered compressors to decrease emissions of formaldehyde; and (4) the implementation of health protective minimum-surface setbacks between underground gas storage facilities and human populations. (See Recommendation 1.9 in the Summary Report.)

<u>Community Symptom-based Environmental Monitoring for High Priority Chemicals</u>

Finding: Symptom reporting and environmental monitoring in Porter Ranch, CA, during and after the 2015 Aliso Canyon incident indicate that chemicals and materials sourced from the SS-25 well entered residences, demonstrating clear indoor and outdoor exposure pathways. However, air pollutant exposures during the SS-25 event are significantly uncertain with respect to characterizing health-relevant exposures, because (1) detection limits for air pollutants such as benzene, mercaptans, and other toxic air pollutants during the SS-25 blowout were often above health and/or odor thresholds; (2) air and other environmental monitoring during much of the time of the SS-25 blowout was non-continuous; and (3) only a small fraction of pollutants known to be associated with UGS facilities was included in the monitoring.

Conclusion: Effective health risk management requires continuous, rapid, reliable, and sensitive (low detection limit) environmental monitoring in both ambient and indoor environments that include chemicals of known concern. (See Conclusion 1.6b in the Summary Report.)

Recommendation: To support a more detailed exposure assessment in communities located near underground gas storage facilities, procedures need to be in place to be able to: (1) rapidly deploy a network of continuous, reliable, and sensitive indoor and outdoor sensors for high priority chemicals, capable of detecting emissions at levels below thresholds for minimum risk levels; and (2) employ real-time atmospheric dispersion modeling to provide information about the dispersion and fate of a large release of stored natural gas to the environment. (See Recommendation 1.6b in the Summary Report.)

Chemical Disclosure for Storage Wells and Associated Aboveground Operations

Finding: While chemicals used in oil and gas production during routine activities (e.g., drilling, routine maintenance, completions, well cleanouts) and well stimulation (e.g., hydraulic fracturing and acid stimulation) are reported for all other wells in the South Coast Air Quality Management District, no such disclosures are made for UGS wells. And this is true for UGS facilities statewide. UGS operators disclose chemical information to the California Environmental Reporting System (CERS) for chemicals stored on-site; however, this information is not publicly available for all facilities, does not include what the chemicals are used for, or the mass or frequency of use on-site, and often lists product names without unique chemical identifiers. As such, it is likely that on-site chemical use occurs, but the composition of those chemicals, the purpose, mass, and frequency of their use, and their associated human health risks during normal and off-normal events at UGS facilities, remain unknown.

Conclusion: To be able to conduct comprehensive hazard and risk assessment of underground gas storage facilities, risk managers, regulators, and researchers need access to detailed information for all chemicals used in storage wells and in associated infrastructure and operations. (See Conclusion 1.22 in the Summary Report.)

Recommendation: The Steering Committee recommends that operators be required to disclose information on all chemicals used during both normal and off-normal events. Each chemical used downhole and on underground gas storage facilities should be publicly disclosed, along with the unique Chemical Abstract Service Registry Number (CASRN), the mass, the purpose, and the location of use. Studies of the community and occupational health risks associated with this chemical use during normal and off-normal events should be undertaken. (See Recommendation 1.22 in the Summary Report.)

Explosion and Flammability Considerations

Finding: During large LOC events, downwind methane concentrations can be higher than flammability or explosion limits. This poses a significant threat to people and property due to sustained fires and collapse of buildings and infrastructure from explosions. For risk assessment purposes, this study compared predicted concentrations from atmospheric dispersion models with methane concentration flammability limits. There are air dispersion conditions and failure scenarios that can present risks of severe harm to workers and nearby communities if a release of flammable gas is ignited due to exposure to high temperatures and associated radiation from a blast. Based on our modeling, the methane concentrations in the close vicinity of the leakage points may exceed the lower flammability limits for typical "off-normal" leakage fluxes. Flammable zones are typically not expected to extend beyond UGS facility boundaries, unless the leak rates are extremely large, i.e., larger than the fluxes experienced in the 2015 Aliso Canyon incident.

Conclusion: Each underground gas storage facility needs an assessment of emitted natural gas combustion potential, and a mapping of the flame and the thermal dispersion associated with this combustion. (See Conclusion 1.10 in the Summary Report.)

Recommendation: Regulators and decision-makers should require the implementation and enforcement of best practices to reduce the likelihood of ignition of flammable gases in and near underground gas storage facilities. Occupational and community hazard zones should be delineated for each underground gas storage facility (possibly based on bounding simulations conducted with atmospheric dispersion models) to focus risk mitigation on elimination of leakage and ignition sources (loss prevention) and safer site-use planning. (See Recommendation 1.10 in the Summary Report.)

1.5 ATMOSPHERIC MONITORING FOR QUALIFICATION OF GHG EMISSIONS AND UGS INTEGRITY ASSESSMENT IN CALIFORNIA

GHG Emission Measurement and Analysis

Finding: Observed methane emissions vary by factors >10× across sites, with three sites (Honor Rancho, McDonald Island, and Aliso Canyon) dominating emissions. Within sites, variations of ~3-5× occur over time. Directly observed emissions are 2-5× higher than the average of emissions reported to CARB. Observations suggest total California UGS emissions are ~9.3 GgCH4/yr (≈ 1% California total methane emissions) which is < 0.1% total California GHG emissions, with compressors and aboveground infrastructure apparently contributing the majority of the emissions.

Conclusion: Though there are discrepancies between directly observed greenhouse gas emissions and those reported to CARB, average methane emissions from underground gas storage facilities are not currently a major concern from a climate perspective compared to other methane and GHG sources, such as dairies and municipal solid waste landfills. However, average methane emissions from underground gas storage facilities are roughly equivalent to an Aliso Canyon incident every 10 years, and hence worthy of mitigation. (See Conclusion 1.11 in the Summary Report.)

Recommendation: An improved methane monitoring program is needed for better quantitative emissions characterization that allows for direct comparison with reported emissions. The monitoring program could benefit from a combination of persistent on-site measurements and higher accuracy, periodic independent surveys using airborne- and surface-based measurement systems. (See Recommendation 1.11a in the Summary Report.)

Recommendation: Average underground gas storage methane emissions should be monitored primarily for safety and reliability (see Recommendation 1.12 below), since the net GHG effect of underground gas storage facilities is relatively small. However, most of the current GHG leakage detection measurements (e.g., methane concentrations) conducted at underground gas storage facilities point to easily mitigatable sources for aboveground leaks, such as compressors or bypass valves. Thus, with regard to reducing GHG emissions, facilities should maintain and upgrade equipment (particularly compressors and bypass valves) over time, repair leaking equipment (e.g., following the new CARB regulations for natural gas facilities), and reduce leakage and releases (blowdowns) during maintenance operations. (See Recommendation 1.11b in the Summary Report.)

<u>Atmospheric Monitoring for Integrity Assessment</u>

Finding: Natural gas at UGS facilities provides an atmospheric tracer that can enable efforts to monitor integrity of surface and subsurface infrastructure — potentially offering early warning to minimize the impact of leaks and avoid loss-of-containment and other hazardous situations for some failure modes. Methane in particular is both the primary constituent of natural gas and can be measured by a variety of methods to identify, diagnose, and guide responses to integrity issues. Methane also serves as a proxy for other compounds that may be co-emitted, including air toxics such as benzene. There are many methane measurement methods that can be applied to UGS leak detection; however, they have differing capabilities and limitations. Several of these methods have been successfully demonstrated in operational field conditions at Aliso Canyon, Honor Rancho, and other facilities, including several examples that illustrate the potential for coordinated application of multiple synergistic observing system “tiers.” As of October 1st, 2017, regulations of the California Air Resources Board (CARB) went into effect. These regulations require UGS operators to continuously monitor meteorological conditions, including temperature, pressure, humidity, and wind speed and direction, monitor predominantly upwind (background) and downwind methane concentrations in air, and carry out daily gas hydrocarbon concentration measurements at each injection/withdrawal wellhead and attached pipelines. If anomalous concentrations of hydrocarbons persist above certain thresholds for certain periods of time, notification must be made to CARB, DOGGR, and the local air district. It is important to note that the purpose of these monitoring requirements is to detect that leakage is occurring, not to quantify emissions (i.e., leakage rates). Once leaks are detected and located, they can be addressed.

Conclusion: Coordinated application of multiple methane emission measurement methods can address gaps in spatial coverage, sample frequency, latency, precision/uncertainty, and ability to isolate leaks to individual underground gas storage facility components in complex environments and in the presence of confounding sources. A well-designed methane emission and leakage detection monitoring strategy can complement other integrity assessment methods—such as the new mechanical integrity testing, inspections, and pressure monitoring now required by the new DOGGR regulations for storage wells—by providing improved situational awareness of overall facility integrity. In addition to supporting proactive integrity assessments, methane emissions monitoring also helps improve accounting of GHG emissions and timely evaluation of co-emitted toxic compounds in response to potential future incidents. (See Conclusion 1.12 in the Summary Report.)

Recommendation: An optimized methane emission monitoring strategy should be devised to provide low latency, spatially complete, and high-resolution information about methane emissions from underground gas storage facilities and specific components of the gas storage system. A program based on this strategy could benefit from a combination of persistent on-site measurements and higher accuracy, periodic independent surveys using airborne- and surface-based measurement systems. These emissions measurements would complement the on-site wellhead and upwind-downwind concentration-based leakage-detection measurements now required by CARB. The scientific community should be engaged in helping underground gas storage operators and regulators design such a monitoring strategy, and should be serving in an ongoing advisory capacity to ensure that best practices and new developments in monitoring technology can be implemented in the future. (See Recommendation 1.12 in the Summary Report.)

Assessment, Management, and Mitigation Actions in Case of Local Methane Leakage Observations

Finding: At Aliso Canyon, McDonald Island, and Honor Rancho, where total methane emissions have been measured to be above 250 kg/hr in some of the recent airborne measurement campaigns, the sources of these emissions were localized in most cases as originating from above-ground infrastructure such as compressor stations or leaking valves. This is a maintenance or repair issue but not an early warning indicator for large loss-of-containment events. (The 250 kg/hr emissions rate is a limit defined by DOGGR in its order allowing resumption of injection at the Aliso Canyon underground gas storage facility. If this limit is exceeded, the operator must continue weekly airborne emissions measurements until the leaks have been fixed, no new leaks have been found, and emissions are below 250 kg/hr.) But local methane hot spots could also be associated with wellheads or emissions from the ground near gas storage wells, in which case timely assessment and mitigation response can be essential in preventing the evolution of a small leak into a major blowout.

Conclusion: Periodic airborne and surface-based methane monitoring strategies provide the ability for detection of localized leaks within facilities, which in turn allow for early identification, diagnosis, and mitigation response to prevent smaller leaks from becoming a major loss-of-containment incident. (See Conclusion 1.13 in the Summary Report.)

Recommendation: The Steering Committee recommends that DOGGR or CARB develop a protocol for all facilities defining the necessary assessment, management, and mitigation actions for the cases where periodic airborne and surface-based methane surveys identify potential emission hot spots of concern. (See Recommendation 1.13 in the Summary Report.)

Integration, Access, and Sharing of Monitoring/Testing Data

Finding: Since the 2015 Aliso Canyon incident, increasing institutional monitoring requirements, new regulatory monitoring/testing standards, and various measurement and data collection campaigns conducted in academic settings have provided a large amount of information on UGS facilities, in particular with regards to integrity issues and potential loss-of-containment. For example, airborne based measurements of local methane emissions can potentially offer early warning of well integrity concerns, which can then be followed up by detailed well integrity testing and mitigation. Meanwhile, persistent hotspots of gas odorants from environmental monitoring in communities might point to unknown gas leaks in nearby facilities. However, the value of these complementary data types is limited if they are not integrated and maintained in a central database and if access is only given after long delays.

Conclusion: The Steering Committee recognizes the value of coordinated and integrated assessment of complementary types of data on methane emissions and other environmental monitoring to be able to act early and avoid potentially large loss-of-containment incidents. However, the committee is concerned that there is no single data clearing house where (1) the multiple sources of data from required or voluntary reporting/monitoring are collected and maintained; and (2) these data can be easily accessed and evaluated by oversight bodies and the public. (See Conclusion 1.24 in the Summary Report.)

Recommendation: The Committee recommends that these data, particularly on methane concentrations within and near the fence line of the facility and in key locations in adjacent communities, should be posted in real time, informing residents living nearby of potential airborne hazards associated with any loss-of-containment. Data that cannot be posted in real time, because more extensive quality assurance and control is required, should be released at frequent intervals without significant delay from the time of collection, in a standardized digital format. (See Recommendation 1.24a in the Summary Report.)

Recommendation: The Committee further recommends identifying a lead agency in California (e.g., DOGGR, CARB, CPUC) that develops and implements a strategy for the integration, access, quality control, and sharing of all data related to underground gas storage facilities integrity and risk. (See Recommendation 1.24b in the Summary Report.)

1.6 RISK MITIGATION AND MANAGEMENT

Overall Assessment of DOGGR's New Emergency and Proposed Draft Regulations

Finding: The draft DOGGR regulations that will govern subsurface operations at UGS facilities in California contain numerous important provisions that will make UGS safer, and that will also allow for a better understanding of the levels of safety achieved at any specific UGS facility.

Conclusion: The existence of both the emergency DOGGR regulations now in place and the draft permanent regulations still under development represents a major step to reduce risk of loss-of-containment, particularly the requirement for each facility to provide a risk management plan; the requirement of the use of two barriers in wells, e.g., use of tubing and packer; and the requirements for well testing and monitoring. The Steering Committee concludes that the new regulations should profoundly improve well integrity at underground gas storage facilities in California. (See Conclusion 1.14 in the Summary Report.)

Evaluating Risk Management Plans as a Major Element of UGS Integrity

Finding: One of the major and most important elements of both the emergency regulations and the draft permanent regulations is that each UGS facility in California must develop and implement a Risk Management Plan (RMP) with certain specified features as follows: "RMPs shall include a description of the methodology employed to conduct the risk assessment and identify prevention protocols, with references to any third-party guidance followed in developing the methodology. The methodology shall include at least the following: (1) Identification of potential threats and hazards associated with operation of the underground gas storage project; (2) Evaluation of probability of threats, hazards, and consequences related to the events."

Conclusion: Requiring risk management plans and risk assessment studies for each facility is an important step in ensuring underground gas storage integrity, but the draft permanent regulations do not contain enough guidance as to what the risk assessment methodology needs to provide. (See Conclusion 1.15 in the Summary Report.)

Recommendation: The Steering Committee suggests DOGGR make further clarifications and specifications in the risk management plan requirements as follows: (1) the need for each underground gas storage facility to develop a formal quantitative risk assessment, to understand the risks that the facility poses to various risk endpoints (such as worker safety, health of the offsite population, release of methane, property damage, etc.); and (2) the need to develop a risk target or goal for each risk endpoint that each facility should stay below and that is agreed to by the regulator (DOGGR), rather than written into an enforceable government regulation. These two needs, if satisfied, will provide the basis for rational and defensible risk-management decision-making that would not be possible without results from a formal risk assessment and defined risk targets or goals. The committee also provides guidance on a range of other attributes that a risk management plan must contain, including (1) considerations of human and organizational factors as well as traits of a healthy safety culture; and (2) recommendations regarding intervention and emergency response planning. These detailed suggestions are given in Section 1.6 of the main report. (See Recommendation 1.15 in the Summary Report.)

Well Integrity Requirements

Finding: The proposed regulations contain various technical requirements for (1) well construction, (2) mechanical integrity testing, (3) monitoring, (4) inspection, testing, and maintenance of wellheads and valves, (5) well decommissioning, and (6) data and reporting. Overall, the Steering Committee finds these requirements a major step forward to improve well integrity in UGS facilities. In terms of the detailed specifications, the committee has several suggestions for revision, e.g., to clarify ambiguous language, provide additional specification, ensure consistency with industry standards, and balance the benefit of frequent testing with the risk to aging wells from installing instrumentation. These detailed suggestions are given in Section 1.6.4 of the report.

Conclusion: The technical requirements for wells provided in the draft DOGGR regulations contain many provisions that are expected to enhance the safety of well operations at the underground gas storage facilities in California. As with any new regulation, application in the practice over time will be an ultimate test, with an "effective" regulatory framework being one that enhances safety to the point that risks are acceptable, while not placing unnecessary burden on operators. (See Conclusion 1.16 in the Summary Report.)

Recommendation: The Steering Committee recommends that DOGGR considers several detailed suggestions made in Section 1.6 of the main report to improve the specific well integrity requirements in the draft regulations. Also, the committee recommends that the finalized regulations be reevaluated after perhaps five years of application (see Recommendation 1.17 below). (See Recommendation 1.16 in the Summary Report.)

Need for Regular Peer Review or Auditing of New DOGGR Regulations

Finding: It is a common practice in many fields to evaluate the effectiveness of regulations, in particular those that may have been newly developed, on a regular basis by peer-review teams or auditing teams. For example, the Groundwater Protection Council (GWPC) organizes peer reviews of the Class II Underground Injection Control Program in certain states to which the U.S. EPA has delegated regulatory authority. (Class II wells are used only to inject fluids associated with oil and natural gas production—not gas storage.) The peer reviews typically include regulators from other states that are involved in those same programs, but may also involve stakeholders from academia and environmental organizations. Although many different approaches have been used and models for organizing them are widespread, one possible suggestion is to use the Interstate Oil and Gas Compact Commission (IOGCC) to help with this review.

Conclusion: Conducting a peer review or audit of the new DOGGR regulations after a few years of implementation would ensure that (1) the latest science, engineering, and policy knowledge is reflected to provide the highest level of safety; (2) these regulations are consistently applied and enforced across all storage facilities and are thoroughly reviewed for compliance; (3) an appropriate safety culture has been fully embraced by operators and regulators; and finally (4) the regulator has the necessary expert knowledge to conduct a rigorous review of the regulatory requirements. (See Conclusion 1.17 in the Summary Report.)

Recommendation: The Governor should ensure that the effectiveness of the DOGGR regulations and the rigor of their application in practice be evaluated by a mandatory, independent, and transparent review program. Reviews should be conducted in regular intervals (i.e., every five years) following a consistent set of audit protocols to be applied across all storage facilities. Review teams would ideally be selected from a broad set of experts and stakeholders, such as regulators from related fields in other states, academia, consultants, and environment groups. Results from the mandatory review should be published in a publicly available report with an opportunity for public comment. Responsibility for the design and executing of the review program should either be with a lead agency designated by the Governor, or alternatively could be assigned to an independent safety review board appointed by the Governor. (See Recommendation 1.17 in the Summary Report.)

<u>Acceptability of the Various Risks: Risk Targets, Risk Goals, Risk Acceptability Criteria</u>

Recommendation: It is recommended that either DOGGR (as part of its regulations or policies) or the industry (perhaps through an industry consortium) determine, for each category of risk, a threshold level of risk, and promulgate these threshold levels as risk targets or goals. There are many possible ways in which a risk target or goal might be formulated, and of course for every risk category, a different target or goal is necessary. An example or two may suffice to provide the general idea.

<u>Risk Management Plans—Methodology for Understanding the Current "Level" of Risk</u>

Recommendation: To complete Element #1 successfully, a facility-specific quantitative risk analysis must be undertaken. The risk analysis must provide a quantified estimate for each analysis "result," including an estimate of the uncertainties in the numbers, and must describe each important contributor in a way that supports later Risk Management Plan Elements (see below), such as comparisons with acceptable risk levels, decisions on further monitoring or analysis, decisions on intervention, and so on. Therefore, it is recommended that the proposed new DOGGR regulations should describe what must be accomplished by an acceptable risk assessment approach and methodology, along with information about how DOGGR will review a given approach and methodology to assure that it is adequate. Although each facility can select its own approach and methodology, this is necessary in the DOGGR regulations to ensure that sufficient rigor and thoroughness are used across all facilities in California. The methodology must address each risk category considered in the Risk Management Plan.

Recommendation: To address the issue raised here, we propose the following draft language capturing the concerns described above:

> *[proposed for 1726.3(b)] The methodology shall include at least the following:*

1. *Identification of the most important potential accident scenarios associated with operation of the underground gas storage project, based on a detailed description of the characteristics of each facility (number of wells, age, operating scheme, etc.);*

2. *Evaluation of the frequency (for example, the annual probability) of each such accident scenario, and the range of consequences associated with it, including estimates of the uncertainties in the numerical values;*

3. *For each important accident scenario, identification of the principal equipment failures, the principal external initiating events if any (earthquakes, flooding, aboveground industrial accidents, etc.), the principal operational errors, and other aspects that contribute to each accident scenario, and for each a description and quantification of its role relative to other contributors in the evolution of the scenario;*

4. *For each scenario leading to an accidental release, identification of the important engineered or natural features that affect the extent of the various end-point consequences, and a quantification of their relative roles, including an estimate of the uncertainties in the quantification.*

Conclusion: The draft DOGGR regulations ignore how human and organizational factors as well as a healthy safety culture drive safety outcomes and performance. (See Conclusion 1.18 in the Summary Report.)

Recommendation: The final DOGGR regulations for underground gas storage facilities should explicitly address the importance and role of human and organizational factors as well as safety culture, commensurate with their impact. DOGGR could follow the State of California's Department of Industrial Relations' (DIR) Occupational Safety and Health Standards Board and at least adopt the two new "Human Factors" and "Safety Culture" elements in the recently revised and updated CalOSHA Process Safety Management for Petroleum Refineries regulation, which became effective on October 1, 2017. In this context, DOGGR should also consider applying other related and applicable elements of the new CalOSHA regulation to underground gas storage safety, such as "Management of

Organizational Change.” (See Recommendation 1.18 in the Summary Report.)

Risk Management Plan—Routine (or periodic) Monitoring, Data collection, and Analysis

Recommendation: It is recommended that DOGGR require that monitoring, data collection, and analysis must be informed using the insights from a scenario-by-scenario risk analysis to assist decision-makers in determining what to monitor, what data to collect, what to analyze, and why. Especially for scenarios characterized by a low probability of occurrence but a potential for high consequences, only a risk analysis that identifies and characterizes them can reveal the optimal intervention(s) to reduce their potential consequences.

Recommendation: Throughout the new DOGGR draft regulation are requirements for monitoring, data collection, and analysis. Each of these requirements must be linked directly to an underlying risk analysis that can support a determination of the technical basis for deciding, for that activity, (1) how often, (2) with how much detail or accuracy, and (3) how much uncertainty in the measurements is tolerable, and why. An explicit linkage in the language of the requirements to the specific accident scenarios at issue can help provide the technical basis for these decisions.

Risk Management Plan—Intervention Activities

Recommendation: A Risk Management Plan must include a description of the decision-making process including criteria for undertaking interventions of various types. This is needed even though many of the details cannot be provided in the RMP, because each intervention is by its nature highly situation specific.

Recommendation: A change must be made to replace the words “prevention protocols” with “intervention protocols” everywhere in regulatory subsection 1726.3(b).

Risk Management Plan—Emergency Response Plan

Recommendation: A Risk Management Plan must include an emergency response plan that establishes both requirements and expectations, and that is based on a careful understanding of the given facility’s risk profile.

Risk Management Plan—Documenting the Results

Recommendation: A Risk Management Plan must include a description of what documentation is required, or desirable, and why. Depending on the circumstances, certain documentation requirements may be specified, and others suggested.

Operating Crew Training

Conclusion: There is no California requirement at today's operating underground gas storage facilities for the regular training of the operating and maintenance crew, nor for the use of written procedures to assist the crew in its response to off-normal conditions and events that might lead to a severe accident. Regular training and written procedures have been demonstrated in other industries to improve safety around off-normal conditions and events. It is likely that underground gas storage could benefit similarly from analogous training and procedures. (See Conclusion 1.19 in the Summary Report.)

Recommendation: The Steering Committee recommends that at each operating underground gas storage facility in California, a requirement be put in place for the regular training of the operating and maintenance crew, using written procedures. This could be either a requirement developed and implemented voluntarily by the industry itself, or a requirement embodied in a government regulation. It is further recommended that the requirement be placed in the Risk Management Plan section of the new DOGGR regulations. (See Recommendation 1.19 in the Summary Report.)

Capability to Predict the Site-specific and Release-specific Transport and Fate of Releases

Conclusion: Although a range of practical and sophisticated models are readily available for predicting the impacts of off-normal LOC events, there is currently no requirement for UGS facilities to possess, or have access to, atmospheric dispersion models that can predict the fate of natural gas emitted from a facility. Also, the lack of temporal and spatially varying emission data from each facility, as well as the past lack of reliable local meteorological data (now addressed by the new CARB regulations for methane emissions from natural gas facilities), make it difficult to accurately simulate the atmospheric dispersion and concentrations of gas leakage from UGS facilities. (See Conclusion 1.20 in the Summary Report.)

Recommendation: Each operating facility in California should arrange to develop a capability to predict the atmospheric dispersion and fate of a large release of natural gas to the environment in near real time, and the impact of such a release on workers, the local population, and the broader environment. The simulation capability should be developed by an independent (ideally single) institution with the technical capacity (i.e., modeling skills) and transparency that meet the public's demand for trust. (See Recommendation 1.20 in the Summary Report.)

Database for Routine Reporting of Off-normal Events Relevant to Safety

Conclusion: Experience from other industries shows that the reporting of minor off-normal events and failures can be very useful when shared and aggregated for the purposes of improving operations and learning from mistakes. (See Conclusion 1.23 in the Summary Report.)

Recommendation: The Steering Committee recommends that a database be developed for the reporting and analysis of all off-normal occurrences (including equipment failures, human errors in operations and maintenance, and modest off-normal events and maintenance problems) at all underground gas storage facilities in California. An example of one kind of input to this database is the required reporting of leak detection and repair required under the new CARB regulations for methane emissions from natural gas facilities. The database should be made publicly available to enable others to derive lessons-learned from it (See Recommendation 1.23 in the Summary Report.)

Underground Gas Storage Project Data Requirements (Section 1726.4)

Recommendation: To maintain consistency in reporting across the industry it is recommended that a definition of a change in the project data be provided. Additionally, a predefined timeframe for reporting such changes should be specified. Furthermore, we recommend a review of all data be done every few years.

Well Construction Requirements (Section 1726.5)

Recommendation: Clarification of what qualifies as a primary barrier is recommended to avoid confusion. Because many of these wells are repurposed, i.e., conversions of existing, old oil and gas wells, we recommend that the evaluation of cement bond integrity be addressed throughout the lifetime of a well and not just at initial casing installation.

Mechanical Integrity Testing (Section 1726.6)

Recommendation: We recommend the following industry standards for logging to demonstrate external mechanical integrity:

(A) Temperature Survey. *A temperature survey performed to satisfy the requirements of external mechanical integrity testing shall adhere to the following:*

1. *The well must be taken off injection at least twenty-four hours but not more than forty-eight hours prior to performing the temperature log, unless an alternate duration has been approved by the DOGGR.*

2. *All casing and all internal annuli must be completely filled with fluid and allowed to stabilize prior to commencement of logging operations.*

3. *The logging tool shall be centralized, and calibrated to the extent feasible.*

4. *The well must be logged from the surface downward, lowering the tool at a rate of no more than thirty feet per minute.*

5. *If the well has not been taken off injection for at least twenty-four hours before the log is*

run, comparison with either a second log run six hours after the time the log of record is started or a log from another well at the same site showing no anomalies shall be available to demonstrate normal patterns of temperature change.

6. *The log data shall be provided to the DOGGR electronically in either LAS or ASCII format.*

(B) Noise Log. A noise log performed to satisfy the requirements shall adhere to the following:

1. *Noise logging may not be carried out while injection is occurring.*

2. *All casing and all internal annuli must be completely filled with fluid and allowed to stabilize prior to commencement of logging operations.*

3. *Noise measurements must be taken at intervals of 100 feet to create a log on a coarse grid.*

4. *Noise logging shall occur upwards from the bottom of the well to the top of the well.*

5. *If any anomalies are evident on the coarse log, there must be a construction of a finer grid by making noise measurements at intervals of twenty feet within the coarse intervals containing high noise levels.*

6. *Noise measurements must be taken at intervals of ten feet through the first fifty feet above the injection interval and at intervals of twenty feet within the 100-foot intervals containing:*

   a. The base of the lowermost bleed-off zone above the injection interval;

   b. The base of the lowermost USDW; and

   c. In the case of varying water quality within the zone of USDW, the top and base of each interval with significantly different water quality from the next interval.

7. *Additional measurements must be made to pinpoint depths at which noise is produced.*

8. *A vertical scale of one or two inches per 100 feet shall be used.*

(C) Cement Evaluation Logging. A cement evaluation log performed to satisfy the requirements of this section shall adhere to the following:

1. *Cement evaluation tools shall be calibrated and centralized to the extent feasible.*

2. *Cement evaluation tools shall be run initially under surface pressure and then under pressure of at least 1,500 psi.*

3. *If gas is present within the casing where cement evaluation is being conducted, then a padded cement evaluation tool shall be run in lieu of an acoustic tool.*

   (D) <u>Anomalies</u>*. The operator shall take immediate action to investigate any anomalies, as compared to the historic record, encountered during testing as required. If there is any reason to suspect fluid migration, the operator shall take immediate action to prevent damage to public health, safety, and the environment, and shall notify the DOGRR immediately.*

<u>Monitoring Requirements (Section 1726.7)</u>

Recommendation: We recommend the collection and recording of pressure data for all uncemented annuli and injection tubing. Additionally, observation wells should be utilized at all UGS sites, and installation of groundwater monitoring wells to evaluate USDW should be considered.

<u>Inspection, Testing, and Maintenance of Wellheads and Valves (Section 1726.8)</u>

Recommendation: All wellheads and valving should be function-tested and pressure-tested at least annually, and should be rated to withstanding the maximum allowable operational pressures within the UGS field.

<u>Well Leak Reporting (Section 1726.9)</u>

Recommendation: We recommend that a record of mandatory reporting of all integrity issues should be implemented independent of the size of the release. The time line and urgency of the reporting can be varied, depending on the gravity of the release according to the definition in this section of the regulations.

<u>Requirements for Decommissioning (Section 1726.10)</u>

Recommendation: We recommend that the UGS regulations describe an adequate path to wellbore abandonment. Furthermore, DOGGR needs to determine whether the current industry standards are adequate.

1.7 RISK-RELATED CHARACTERISTICS OF UGS SITES IN CALIFORNIA

<u>Site-specific Hazard and Risk Assessment</u>

Finding: The hazards, vulnerabilities, and risk levels are generally different for facilities that store gas in former gas reservoirs versus former oil reservoirs, and also differ qualitatively among individual facilities based on their unique characteristics. Identification of such differences allows the high-level or preliminary assessment of which UGS sites in California may present higher risk to health, safety, and the environment than others, overall or for certain risk categories and scenarios. High-level identification of such risk-related differences can lead to more specialized and effective risk management and mitigation approaches for each setting.

Conclusion: Qualitative assessment of risk-related characteristics of the California underground gas storage facilities points to relatively larger potential risk in facilities that have older repurposed wells often in former oil reservoirs, are located in hazard zones for seismic or other natural disaster risks, may have a higher rate of loss-of-containment incidents, and are located near large populations centers. (See Conclusion 1.25a in the Summary Report.)

Conclusion: Of the currently operating facilities, Playa del Rey stands out as a facility with risk-related characteristics of high concern for health and safety relative to the other facilities in California, followed by Aliso Canyon, Honor Rancho, La Goleta, and Los Medanos. (See Conclusion 1.25b in the Summary Report.)

Recommendation: The State of California should conduct a comparative study of all underground gas storage facilities to better understand the risk of individual facilities relative to others. This comparative study should be based on the risk management plans being developed for each facility and should be commissioned when such risk management plans have matured to the point that they comprise formal risk assessments and mitigation plans (e.g., in five years). The end product would be a table similar to Table ES-1.1 in the Executive Summary, but the revised table would be based on quantitative rather than qualitative information. The quantitative risk-related information on each facility can then be used by decision-makers to examine the tradeoffs between risks associated with individual facilities and their importance in meeting the demands of the natural gas supply. (See Recommendation 1.25 in the Summary Report.)

Key Question 2

Does California need underground gas storage to provide for energy reliability through 2020?

1.1 WHAT IS THE ROLE OF GAS STORAGE IN CALIFORNIA TODAY?

Finding: While forecasts suggest falling total gas demand out through 2030, none of the forecasts break out how much gas might be necessary to firm intermittent renewable generation and the timing of that need, factors which can affect the need for gas storage.

Finding: Nearly every winter has a month with average daily demand that exceeds, or nearly exceeds, pipeline take-away capacity.

Conclusion 2.1: Without gas storage, California would be unable to consistently meet the winter demand for gas.

Conclusion 2.2: If California had no gas storage, the burden of allowing relatively constant gas production to match to seasonally varying demand would shift to production and storage located more than 1,000 miles upstream from California.

Finding: California does not have enough intrastate pipeline take-away capacity to meet forecasted peak winter demand. California's intrastate pipeline capacity (7.5 Bcfd) is insufficient to meet the forecasted 11.8 Bcfd peak load corresponding to a very cold winter day.

Conclusion 2.3: California does not have enough intrastate pipeline take-away capacity to meet forecasted peak winter demand. Currently, winter peak load of 11.8 Bcdf can only be met reliably if storage can deliver 4.3 Bcfd.

Finding: The California utilities, together, have enough storage delivery capacity to meet winter peak day demand based on historic regulatory and operational requirements with about 0.5 Bcfd surplus that can be utilized in case of gas system outages.

Finding: Average daily scheduling of gas delivery generally works because the gas company covers the hourly mismatch between at deliveries and variable usage. Electric generation load causes the change in gas load shown in Figure 11 in hours 12 through 7. Since electric generators have to schedule the same quantity of gas delivery each hour, the incremental supply often comes from storage.

Conclusion 2.4: Gas storage provides crucial hourly balancing for the gas system in all seasons. Without gas storage, California would be unable to accommodate the electricity generation ramping that now occurs nearly every day and that may increase as more renewables are added to the grid.

Finding: Underground gas storage protects California from outages caused by extreme events, notably extreme cold weather that can drastically reduce out-of-state supplies.

Conclusion 2.5: Gas storage could increasingly be called on to provide gas and electric reliability during emergencies caused by extreme weather and wild fires in and beyond California. Both extreme weather and wild fire conditions are expected to increase with climate change. These emergencies can threaten supply when demand simultaneously increases.

Conclusion 2.6: Seasonal price arbitrage can be considered a second-order benefit of utility-owned gas storage. In theory, the utilities could purchase financial contracts to achieve this price benefit. As long as California needs storage to meet winter reliability needs, however, it is prudent to also capture price benefits when they are available. This allows California to avoid the transaction costs that would be associated with using financial contracts to hedge winter prices.

Finding: Natural gas storage in California also enhances market liquidity. It allows marketers a place to store gas for short periods of time (in contrast to the utilities storing gas primarily for winter). This extra degree of freedom helps to manage dis-synchronies between sales contract starts and stops; the timing of new production coming on line; or maintenance periods at a production, gathering or pipeline facility.

Conclusion 2.7: Storage allows access to gas supply in local markets rather than having to wait for it to be transported. In short, storage provides more options to dispose of or to access supply.

Conclusion 2.8: The overarching reason for the utilities' underground gas storage is to meet the winter demand for gas. If storage capacity is sufficient to help meet winter demand, it is then able to perform all the other named functions, including intraday balancing, compensating for production which is not aligned with demand, creating an in-state stockpile for emergencies, and allowing arbitrage and market liquidity.

Recommendation 2.1: In evaluating alternatives that would reduce dependence on underground gas storage and shift norms about controlling interruptibility, the State should obtain detailed analysis of the gas system to ensure that the balancing roles gas storage plays on all timescales can be effectively managed by other means. This analysis should include hydraulic modeling of the gas system. The State should also take into account the role these facilities have had in addressing emergency situations, including extreme weather and wildfires.

1.2 FACTORS THAT MAY BE CAUSING ROLE OF GAS TO CHANGE

Conclusion 2.9: Without gas storage, California would be unable to accommodate the electricity generation ramping that now occurs nearly every day and that may increase as more renewables are added to the grid.

1.4 ALTERNATIVES TO UNDERGROUND GAS STORAGE (TO 2020)

Finding: Based on recent pipeline construction costs, we estimate a total cost of close to $15 billion to add 4.3 Bcfd of large-diameter intrastate pipeline capacity and one new interstate pipeline, should California have no underground gas storage.

Finding: Supplying California's full winter peak day demand completely with gas delivered via pipeline on the day it is needed instead of using gas stored in California pushes the problem of matching supply with demand onto upstream gas pipeline operators and producers.

Conclusion 2.10: Construction of additional pipelines to replace underground gas storage in the 2020 timeframe would cost approximately $15B, would be extremely difficult to get done by 2020, and would shift the risk of supply not meeting demand to upstream, out-of-state supplies.

Finding: California could replace all underground gas storage required today with LNG peak shaving units and meet the 11.8 Bcfd extreme winter peak day demand forecast.

Conclusion 2.11: Replacing all underground gas storage with LNG peak shaving units to meet the 11.8 Bcfd extreme winter peak day demand forecast for 2020 would be extremely difficult to permit and would require about $10B.

Conclusion 2.12: The number of containerized LNG units required to generate each MWh suggest containerized LNG does not appear viable at the scale required to replace California's 4.3 Bcfd winter peak need for underground gas storage use. It may, however, have application in meeting system peaks for a few hours or supporting power plant demands for a few hours. Though, it would require 2,000 containers to support a 50 MW power plant for four hours, and these containers would have to be transported to a power plant, which would incur potential safety issues, increased emissions, and complexity.

Conclusion 2.13: As with the containerized LNG, far too many "CNG In A Box" containers would be needed to replace California's underground storage, but applications such as providing a few hours of gas at a specific location such as a peaking power plant or a refinery could make sense.

Conclusion 2.14: Augmenting gas supply to San Diego with LNG from Sempra's terminal in Mexico would provide a short-term, albeit relatively small (on the order of 300 MMcfd), impact on the need for gas storage in Los Angeles at a small marginal cost, and would not require construction of new facilities.

Finding: In addition to the fact that only small amounts of renewable natural gas are likely to be available by 2020, storing this gas to help meet winter demand and to provide daily ramping would still require use of underground gas storage.

Finding: Gas-fired furnaces overwhelmingly supply building space heating in California and this use results in the winter peak demand for gas. California has no policies specific to electrification of building heat, therefore the source of building heat will not likely switch to electricity for several decades (for more information, see Chapter 3).

Conclusion 2.15: No method of conserving or supplying electricity—including electricity storage (batteries, pumped hydroelectric, compressed air storage, etc.), new transmission, energy efficiency measures, and demand response—can replace the need for gas to meet the winter peak in the 2020 timeframe. The winter peak is caused by the demand for heat, and heat will continue to be provided by gas, not electricity, in that timeframe. Gas storage is likely to remain a requirement for reliably meeting winter peak demand.

Finding: Meeting all of California's 2,830 MMcfd of unmet summer demand via electricity from energy storage would require approximately 420,000 MWh of electricity storage. Cost estimates for energy storage are evolving rapidly. The current cost of a 420,000 MWh electricity storage system capable of offsetting all gas storage for a peak summer day would be approximately $174 billion at the current low end of Lazard's (2016) cost range estimate ($417/kWh). If costs fall an additional 75%, the cost would be $44 billion to offset the summer peak demand for electricity, but this would do little to address the winter peak driven by demand for gas-fired heat.

Finding: Current CPUC storage mandates could offset roughly 8% of the peak gas requirement for electricity in the peak summer month (assuming four hours of storage).

Finding: Energy efficiency measures including the combination of committed savings for natural gas, combined with the reductions expected from AAEE (ignoring the uncertainty in its calculation) and the doubling required under SB 350, appear to total less than 400 MMcfd (assuming all of the electric side savings reduce the need for gas-fired generation). If achieved every day, this could remove the need to meet that same demand with gas from storage, but comes nowhere near offsetting California's 4.3 Bcfd shortage on a winter peak day or any other winter day. The actual impact would depend exactly which measures are adopted, what technologies are affected, and what the hourly use pattern changes are.

Finding: The demand response potential appears large enough to offset a good portion of the withdrawal from storage needed to support intraday load balancing by electricity generators but demand response cannot be called upon routinely enough to fully replace the need to use gas from underground storage.

Conclusion 2.16: We could not identify a technical alternative gas supply system that would meet the 11.8 Bcfd extreme winter peak day demand forecast and allow California to eliminate all underground gas storage by 2020. Two possible longer-range physical solutions are extremely expensive, carry their own risks, and would incur barriers to siting. The potential benefits of other approaches that were examined are either small, cannot be estimated at this time, or have negative impacts such as dramatic increase in air toxins and greenhouse gas emissions. No “silver bullet” can replace underground gas storage in the 2020 timeframe.

Finding: Utilities and pipeline companies already use the line pack they have available. Using line pack beyond the normal operational ranges in use today creates a safety concern because a section of overfilled pipe could lead to over-pressurization and potential release of gas.

Finding: Opportunities to shift to out of area generation on gas-challenged days are limited and not reliable.

Finding: The technical assessments for the Aliso Canyon Reliability Action Plans indicate day ahead limits would be helpful, but not a full solution for the winter peak demand. It cannot, for example, eliminate error in the weather forecast.

Finding: If California had no underground gas storage to support shaped nominations, storage somewhere upstream would be required to support the variation in load. However, this remote storage would be unable to respond to short-notice changes.

Finding: Regulatory and operational changes can help to reduce reliance on underground gas storage, but will not eliminate the need for these services.

Conclusion 2.17: Operational and market alternatives do not eliminate the need for underground gas storage to meet winter demand, which serves to overcome the physical difference between peak winter gas demand and the capacity of pipelines to deliver gas. Nor will these measures have much impact on reducing the need to use storage for daily balancing.

1.5 HOW WILL NEW INTEGRITY AND SAFETY RULES AFFECT NATURAL GAS RELIABILITY?

Conclusion 2.18: In the 2020 timeframe, California’s utilities will need to replace some, if not all, of the storage capacity that will be lost by complying with new California regulations to continue to meet peak winter demand. California’s independent storage providers will also need to replace some, if not all, of their lost injection and withdrawal capacity, if they want to maintain historic operating levels.

Finding: PG&E and SoCalGas spent an average of $500,000 per Bcf of cycling capability in 2015 on O&M at their storage facilities. Over time, those expenses appear to have increased at a rate similar to inflation. We could not determine, from information in the public domain, the condition of gas storage facilities or if O&M expense and capital expenditure has been sufficient to maintain the facilities or whether the independent facilities are in better condition and if this might be the case because they are regulated differently or because their owners focus on storage and storage alone.

Recommendation 2.2: DOGGR should conduct detailed facility condition assessments by independent analysts or with stakeholder review, and determine if the level of investment to date is adequate, taking into account the expected cost to implement the new DOGGR rules. This could include an assessment to determine what, if any, impacts occur as a result of different business and regulatory models for utility versus independent storage.

Key Question 3

How will implementation of California's climate policies change the need for underground gas storage in the future?

3.0 INTRODUCTION

Finding: We found no studies that comprehensively assess the volumes of gas needed in the future, i.e., studies that construct complete future possible energy system configurations that meet the climate goals, project the impact of the policies that provide the means to reach these goals, and project the time of use of gas and electricity on every time scale from subhourly to seasonally.

Conclusion 3.1: There are no energy assessment studies that can convincingly inform the future need for underground gas storage in California, because greenhouse gas emissions goals and expectations for energy system reliability remain to be reconciled.

Recommendation 3.1: California should commission or otherwise obtain studies to identify future configurations of energy system technologies for the State that meet emission constraints and achieve reliability criteria on all timescales, from subhourly to peak daily demand to seasonal supply variation. These studies should result in a new hybrid forecasting and resource assessment tool to inform both policy makers and regulators.

3.1 ELEMENTS OF A FUTURE CALIFORNIA ENERGY SYSTEM

Finding: Sub second (frequency regulation) electricity storage can be provided by flywheels or fast-response batteries; response times of minutes to hours and storage capacities of several hours can be provided by thermal storage at the building or power plant, battery storage, and pumped hydroelectric or compressed air energy storage. Flexible load capacity and management of regional transmission capacity are other tools with similar response times to storage that can be called upon for multiple hours at a time.

Conclusion 3.2: Various forms of energy storage could perform intraday balancing, i.e., manage changes in gas demand over a 24-hour period.

Finding: Most forms of energy storage as currently conceived will probably be inadequate for managing daily peak demand that can occur over multiple days and seasonal demand imbalances.

Finding: P2G uses electricity from low-GHG generation technologies to make a substitute chemical fuel. However, similar to natural gas, these chemical fuels require transportation and storage.

Conclusion 3.3: The only currently available means to address multiday or seasonal supply-demand imbalances without using fossil natural gas appears to be low-GHG chemical fuels. These solutions have the same storage challenges as natural gas and may introduce new constraints, such as the need for new, dedicated pipeline and storage infrastructure in the case of hydrogen or CO_2.

Finding: In California (assuming a similar mix of electricity generators as today) climate change could cause a reduction in generating capacity of 2.0-5.2% in summer, with more severe reductions under ten-year drought conditions. Considered altogether, peak demand for electricity generation could increase by 10-15% in 2050.

Conclusion 3.4: Climate change would shift demand for energy from winter to summer, reducing peak gas demand from reserve capacity in winter, but increasing it in summer. Decreases in electric transmission and generation capacity would increase reliance on backup generation and hence underground gas storage, particularly in summer. The net effect would be a stronger reliance on underground gas storage in summer, and possibly increased gas use, than in a scenario without climate change.

3.2 DEMAND FOR UGS IN 2030

Finding: For the scenarios available in the literature, and with some minor exceptions (see below), changes to the energy system from the current state to 2030 are modest. The variation in total annual demand for natural gas in 2030 ranged from between 78% and 100% of current levels in the six GHG-compliant studies we reviewed.

Finding: Among the scenarios included, we found that, by 2030, total non-electricity natural gas demand would decrease by 11-22% relative to today, mainly due to efficiency improvements in the building stock.

Finding: The highest gas use for electricity generation occurs during summer months, roughly July-October (Figure 1). The highest output for both wind and solar also occurs in summer months, peaking in June in both cases (Figure 2). For wind, output declines steadily toward a winter low in December-January, whereas for solar, output remains high through September, after which shorter days and more cloud cover diminish statewide output toward a winter low. Gas use for electricity generation is expected to decline much more in summer than in winter by 2030.

Conclusion 3.5: Although we do not know what the decrease in peak natural gas demand might be, the average reduction in gas use of 600-1200 MMcfd would not be enough to eliminate pipeline capacity deficits that are currently as much as 4.3 Bcfd.

Conclusion 3.6: If California continues to develop renewable power using the same resources the State employs today, these will be at a minimum in the winter, which could create a large demand for gas in the electric sector at the same time that gas demand for heat peaks. Consequently, the winter peak problem that exists today may remain or possibly become more acute. Underground gas storage would then be even more important—unless California deploys complementary strategies, including energy storage, demand response, flexible loads, time-of-use rates, electric vehicle charging, and an expanded or coordinated western grid.

Finding: Based on State policies, CEC projections indicate that overall demand for natural gas will decrease in both summer and winter, allowing for increased flexibility for natural gas injection into storage. However, CEC projects that daily natural gas ramping capability requirements will increase in most months (July through March).

Conclusion 3.7: By 2030, an increase in the need to use gas to supply ramping capability could result in placing greater reliance on underground gas storage.

Finding: January regularly has periods when the combined output of solar and wind is nearly zero, particularly at night when solar is not operating and the wind dies down. In June, average outputs for solar and wind are much higher than January, and a strong anticorrelation between wind and solar keeps the combined output significantly higher than zero in most hours. However, there are still periods where wind output falls to almost zero, sometimes for multiple days at a time, causing dramatic (and sometimes very rapid) drops in total output. In Germany, periods of low solar and wind output are labeled "*dunkelflaute*", which literally translates as "dark doldrums." This variability must be mitigated to ensure reliable electricity. Today the load is balanced mostly with a combination of natural gas turbine generation and hydropower.

Finding: Wind generation capacity (at ~4.9 GW) has not increased since 2014 and is expected to remain constant through 2018. Utility-scale solar PV is expected to more than double, from 4.5 GW in 2014 to 9.1 GW in 2018. The contribution from wind variability will be similar to that shown in Figure 7 and Figure 8 over the next few years, but as solar generation is always zero in the night, the solar variability will continue to grow, exacerbating the total intermittency variation.

Finding: To mitigate expected generation variability, the California Independent System Operator (CAISO) has estimated that almost as much flexible generation capacity as intermittent renewable generation capacity will be needed: for 2018, it estimates that ~16 GW will be needed to balance ~18 GW of intermittent renewables (with this capacity adding some additional intermittent renewables including a portion of behind-the-meter PV generation to the wind and solar capacities mentioned above). This flexible generation capacity varies monthly, with a minimum near ~11 GW in July and a maximum in December.

Finding: Brinkman et al. (2016) explored a model of California's electricity system in 2030 under a 50% GHG reduction scenario, which assumed 56% renewable electricity generation that included 6% customer-sited solar PV. The study found that up to 30 GW of gas generation would be needed to backup these renewables, though half of this capacity would be utilized less than ~25% of the time, making capital investments to insure the availability of such gas generation difficult.

Finding: The ~30 GW of backup natural gas capacity needed in 2030 translates into ~5,000 MMcfd, assuming an average heat rate of ~7,000 Btu/kWh for natural gas turbines (a reasonable assumption based on average heat rates of future California natural gas plants provided from E3). The demand for gas to provide backup for renewable energy comes close to current pipeline import capacity of ~7,500 MMcfd (see Chapter 2).

Conclusion 3.8: Although California's climate policies for 2030 are likely to reduce total gas use in California, they are also likely to require significant ramping in our natural gas generation to maintain reliability. These surges of gas demand for electric generation may require underground gas storage.

Finding: Despite an overall expected decrease in natural gas use in both summer and winter, the use of natural gas for electricity generation may become "peakier" in order to balance the increasingly intermittent output from wind and solar generation, and this potential peakiness could be nearly as large as today on an hourly or seasonal basis. However, these additional demands on UGS are likely to be small compared with the ~1,000 Bcf that is normally injected into and withdrawn from storage every year (see Figure 9 in Chapter 2).

Conclusion 3.9: The total amount of underground gas storage needed is unlikely to change by 2030.

Recommendation 3.2: California should develop a plan for maintaining electricity reliability in the face of more variable electricity generation in the future. The plan should be consistent with both its goals policies and its means policies, notably for 2030 portfolio requirements and beyond, and should account for energy reliability requirements on all timescales. This plan can be used to estimate future gas and underground gas storage needs.

3.3 DEMAND FOR UGS IN 2050

Finding: The maximum rate of deployment of CCS technology exhibited in any scenario is well below the maximum historical rate seen for U.S. expansion of nuclear and natural gas capacities, normalized for California, but the scale-up rates of wind and solar in scenarios which maximize these resources may be close to the historical maximum.

Finding: Meeting seasonal demand peaks and daily balancing, including backing up intermittent renewables are important issues for reliability and these in turn will determine the future need for UGS.

Finding: Future scenarios of the energy system indicate that adding more inflexible and intermittent resources similar to those in use today will challenge reliability and require many fundamental changes to the energy system. Future energy system choices with less intermittent resources will be closer to the current energy system, but will require a wider variety of resources than are currently contemplated in California.

Conclusion 3.10: Future energy systems that include significant amounts of low-carbon, flexible generation might minimize reliability issues that are currently stabilized with natural gas generation.

Recommendation 3.3: California should commit to finding economic technologies able to deliver significantly more flexibility, higher capacity factor, and more dispatchable resources than conventional wind and solar photovoltaic generation technologies without greenhouse gas emissions. These could include biomass, concentrating solar thermal; geothermal; high-altitude wind; marine and hydrokinetic power; nuclear power; out-of-state, high-capacity-factor wind; fossil with carbon capture and storage; or another technology not yet identified.

Conclusion 3.11: Widely varying energy systems might meet the 2050 climate goals. Some of these would involve a form of gas (methane, hydrogen, CO_2) infrastructure including underground storage, and some may not require as much underground gas storage as in use today.

Recommendation 3.4: California should evaluate the relative feasibility of achieving climate goals with various reliable energy portfolios, and determine from this analysis the likely requirements for any type of underground gas storage in California.

Conclusion 3.12: California has not yet targeted a future energy system that would meet California's 2050 climate goals and provide energy reliability in all sectors. California will likely rely on underground gas storage for the next few decades as these complex issues are worked out.

Recommendation 3.5: A commitment to safe underground gas storage should continue until or unless the State can demonstrate that future energy reliability does not require underground gas storage.

Appendix F

Glossary

Abandoned well – a well that is no longer in use and may or may not be plugged.

Accident scenario – see failure scenario. Also sometimes called an "accident sequence."

Adiabatic CAES – Process by which energy is stored via compressing air and storing it in an underground cavern. In this case, the heat of compression is separately stored via packed rock bed or other thermal storage medium. When the energy is needed, the compressed air is expanded using the stored heat of compression. The expansion drives a turbine and produces electricity.

Aliso Canyon – oil field and natural gas storage facility in the Santa Susana Mountains with 114 active UGS wells owned by SoCalGas. It serves more than 11 million customers and provides fuel to 17 natural gas-fired power plants.

Amalgamates – when a metal combines with mercury to form an alloy, e.g. amalgamated aluminum is a compound containing aluminum and mercury that can form in end use equipment if mercury is not removed from natural gas.

Arbitrage – the practice of purchasing an asset at a lower price and selling it at a higher price in order to profit off of the difference between the prices, i.e. if natural gas can be purchased at a low price, injected into underground storage, and withdrawn and sold when prices are higher.

Baseload electricity generation – minimum amount of electricity created and available at any given time in order to meet demand levels.

Biogas – byproduct of biological anaerobic decay of organic matter found in municipal solid waste, landfills, manure, and wastewater. See Biomethane.

Biogas digesters – large tank to collect organic waste and allow bacteria to convert the waste into biogas through the process of anaerobic digestion.

Biomass – organic material such as agricultural byproducts, urban wood, and forest residues and byproducts that can be combusted to produce power.

Biomethane – final product after CO2 and other contaminants are removed from biogas.

Black start – what operators call bringing the electricity system back from complete blackout with all facilities out.

Blowout – the uncontrolled flow of gas, liquids, or solids (or a mixture thereof) from a well into the aboveground environment.

Boring, borehole – cylindrical hole cut into rock or soil by drilling. Casing, cement, and other well components may be inserted into the boring to construct a well.

Breach blowout – the uncontrolled flow of gas, liquids, or solids (or a mixture thereof) out of fractures or cavities in the ground, the flow of fluid, which originates from well failure.

California Sustainable Freight Action Plan – developed by the California State Transportation Agency, California Environmental Protection Agency, and Natural Resources Agency to lead other relevant State departments in developing an integrated action plan that establishes clear targets to improve freight efficiency, transition to zero-emission technologies, and increase competitiveness of California's freight system.

California's Energy Future – A 2013 CCST Study that examines the potential for biofuels among other energy topics.

Cap and trade – market-based strategy designed to reduce greenhouse gases (GHGs) from multiple sources by setting a firm limit or cap on GHGs and minimizing the compliance costs of achieving GHG emissions reduction goals.

Caprock – laterally extensive and low-permeability and/or high capillary-entry-pressure formation (e.g., clay shale or mudstone) above a storage reservoir capable of impeding upward migration of fluid. Synonymous with seal or confining layer.

Carbon capture and sequestration – family of technologies that capture carbon dioxide (CO2) from fuel combustion or industrial processes and transport the CO2 to a suitable storage site.

Casing – large-diameter pipe (usually steel) inserted within a wellbore to stabilize the hole, isolate the different formations to prevent the flow or crossflow of formation fluid, and to provide a means of maintaining control of formation fluids and pressure as the well is drilled and during injection/withdrawal as a secondary barrier. Casings are normally cemented to the formation (borehole wall).

Chemical energy storage – when energy is stored in the bonds of atoms and molecules.

Citygate – a virtual point at which gas is transferred from the backbone transmission system into the local transmission and distribution system.

Closed-cycle evaporative cooling – system that transfers waste heat to the surrounding air through water evaporation instead of transferring the waste heat to surrounding oceans, rivers, and/or lakes.

Compressed air energy storage (CAES) – ambient air is compressed and stored under pressure in an underground cavern. When the energy is needed, the pressurized air is heated and expanded in an expansion turbine driving a generator for power production.

Condition –measured or observed status, state or property of a system, e.g., the pressure or temperature, the composition of the gas stream, etc.

Confining layer – see caprock

Consequences – quantified negative effect of a failure scenario (e.g., evacuations of people due to a well blowout).

Core Customers – core customers include all residential, regardless of load size, commercial customers with annual loads below 250,000 therms, and those commercial customers with annual loads above 250,000 therms who elect to receive the increased reliability associated with core service.

Cryogenic distillation – the process to purify air into pure oxygen, nitrogen, and argon.

Cushion gas – natural gas in the reservoir or storage field that is not withdrawn (not produced) and that serves to maintain pressure and to drive out working gas on any withdrawal cycle. Also known as base gas.

De-carbonize – to remove carbon from an object or system, i.e. an engine; or to reduce/replace the supply/demand for fossil fuels in the energy market through the promotion of renewable energy.

Demand response (DR) – changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time.

Depleted reservoir – hydrocarbon reservoir in which the pressure or mass of reserve has been lowered by production, to the point that further production of oil or gas is sub-economic.

Deviated well – a well drilled using directional drilling methods that is not vertical.

Dispatchable fossil backup – a block of fossil power that can be transmitted (dispatched) as a reliable, controllable, and predictable quantity from the generator to the consumer.

Dispatchable generation – any sort of power that can be transmitted (dispatched) as a reliable, controllable, and predictable quantity from the generator to the consumer.

Dispersion – dilution and mixing effects associated with transport, e.g., dispersion of CH_4 occurs as it is transported by wind.

Distributed energy (DE) – physical and virtual assets that are deployed across the distribution grid, typically close to load, and usually behind the meter. The assets can be used individually or in aggregate to provide services to the electric grid.

Diurnal peak 1-in-10 summer day – the planning standard used by SoCalGas for their local transmission and storage systems. Their systems are designed to provide for continuous firm core and noncore service under a hot summer conditions that are likely to occur only one day in ten years.

Diurnal variation – fluctuation of gas use during the day.

Dunkleflaute – German for "dark doldrums" typically used when renewables, such as wind and solar are less available during the day. This is more common in winter.

Electrification – the process of powering by electricity or conversion of a machine or system to the use of electrical power.

Electrochemically – the use of electricity to initiate a chemical reaction, i.e. use electricity to produce methane from carbon dioxide.

Electrolysis – passing a direct electric current through a substance in order to produce a chemical reaction and the separation of materials, e.g. passing an electric current through water produces hydrogen and oxygen gases.

Energy Action Plan – originally prepared jointly by the California Energy Commission, the Public Utilities Commission and the now-defunct Consumer Power and Conservation Financing Authority to establish shared goals and specific actions to ensure that adequate, reliable, and reasonably-priced electrical power and natural gas supplies are achieved and provided through policies, strategies, and actions that are cost-effective and environmentally sound for California's consumers and taxpayers. The plan was last updated in 2008.

Energy Storage Roadmap – strategy document created by the California Independent System Operator, the California Public Utilities Commission, and the California Energy Commission that identifies policy, technology, and process changes to address challenges faced by the storage sector.

Entrain – see Impingement mortality and entrainment.

Event – an occurrence that is relatively short-lived and which can potentially affect the safety or operation of a system. An earthquake, a pipeline rupture, and a breach blowout are all events bearing on UGS safety.

Failure scenario – sequence of events involving a component or system malfunction that results in consequences.

Fault Tree Analysis (FTA) – an approach to estimating likelihood of failure scenarios by breaking the scenario up into multiple contributing events whose likelihoods are easier to estimate.

Features, Events, and Processes (FEPs) – in risk assessment, FEPs comprise all of the elements potentially relevant to failure scenarios. Catalogues of FEPs can be analyzed to aid in generating a complete and accurate set of failure scenarios.

FEP-scenario approach – a method to aid in generating a complete and accurate set of failure scenarios using Features, Events, and Processes (FEPs).

Fines migration – movement of fine particles within the porous medium commonly resulting in partial plugging of the pore space.

Flexible load capacity – the amount of electricity generation that is flexible (i.e., easy to turn on) to balance varying electricity demand and supply in the grid.

Flywheels – store kinetic energy as an angular momentum of a spinning mass.

Form 10-K – a form that companies must file annually with the Securities and Exchange Commission. It provides a comprehensive overview of a company's business and financial condition and includes audited financial statements.

Formation damage – impairment of the permeability of hydrocarbon-bearing formations by various adverse processes, such as compaction, fines migration, etc.

Frac Gradient/Fracture Gradient – the pressure required to induce fractures in rock at a given depth, or variation in fracturing pressure with depth.

Fractional distillation – the separation of a liquid mixture, like crude oil, into its component parts by selective evaporation and condensation.

Gas Transmission Northwest (GTN) – interstate natural gas pipeline system that transports western Canadian sedimentary basin and rocky mountain-source natural gas to third party natural gas pipelines and markets in Washington, Oregon, and California.

Gasification – a set of chemical reactions that uses limited oxygen to convert a carbon-containing material, like coal or biomass, into carbon monoxide and hydrogen. The resulting gas mixture is called syngas or producer gas and is itself a fuel.

General rate case (GRC) – regulatory proceeding in which a utility lays out what it proposes to spend for the next few years and obtains approval to recover those costs in rates.

Geothermal – relating to the internal heat of the Earth. Geothermal energy is power generated from using this heat, e.g., natural steam, hot water springs, etc.

GHG Compliant – a statewide planning scenario is greenhouse gas (GHG) compliant if it meets the standards for greenhouse gas emissions set by the California Air Resources Board (40% reduction below the 1990 level in 2030, and 80% reduction in 2050). It is non-compliant if total GHG emissions are above these caps. Scenarios developed outside of California were considered GHG compliant if their emissions relative to 1990 (or another recent base year) met the same criteria as in California.

Global Warming Solutions Act – a California State Law (AB 32), which passed in 2006, that fights global warming by requiring the California Air Resources Board (CARB) to develop regulations and a cap-and-trade program to reduce greenhouse gas emissions from all sources throughout the state.

Grid scale energy storage – the storing of electrical energy on a large scale when production exceeds consumption so that it can be returned to the electric grid when production falls below consumption. The largest form of grid scale energy storage is pumped storage hydroelectricity.

Hazard – a potential source of harm to humans, other animals, plants, environment, or infrastructure; synonymous with threat.

Heating value – amount of heat produced by the complete combustion of a unit quantity of fuel.

Henry Hub – benchmark measure of U.S. national price, used to forward contracts on NYMEX. The hub is located in Erath, Louisiana, and at one point some 14 different pipelines interconnected with one another at Henry Hub.

HSIP Gold Data – Homeland Security Infrastructure Program infrastructure geospatial data inventory assembled by the National Geospatial–Intelligence Agency (NGA) in partnership with the Department of Homeland Security (DHS).

Hydrocarbon reservoir – a subsurface basin of naturally occurring hydrocarbons, such as crude oil or natural gas, contained in porous or fractured rock formations.

Hydrocarbons – organic compounds consisting entirely of hydrogen and carbon. Most hydrocarbons found on Earth naturally occur in crude oil.

Hydrogen –the first chemical element in the periodic table, which normally exists as a colorless, odorless, tasteless, diatomic gas (H2).

Hydrogen blending – the concept of blending hydrogen in natural gas pipeline networks.

Hydrogen embrittlement – the process by which metals can become brittle and fracture when hydrogen dissolves into the metal.

Hydrokinetic – relating to moving water. Hydrokinetic energy is the energy harnessed from the flowing water, tides and currents in rivers and oceans, typically by using turbines.

Imbalance – difference between a customer's natural gas usage and the gas scheduled for delivery.

Impingement mortality and entrainment – the effects of cooling water withdrawals on aquatic organisms. Impingement is the trapping of large aquatic organisms against the water intake screens. Entrainment is the carrying of small aquatic organisms into the power plant, which effectively kills them via heat, turbulence and/or chemicals.

Incident – an event or occurrence affecting a UGS facility involving any or all of the following: gas release significant enough to warrant reporting, injury/loss of life, damage to property or infrastructure.

Injection – delivery of fluid (liquid or gas) from the ground surface to the reservoir via wells.

Integrated gasification combined cycle (IGCC) – a type of power plant that uses a high-pressure gasifier to turn fuels (typically coal or natural gas) into syngas, which is used as fuel for the gas turbine. The excess steam produced by the syngas coolers is added to the steam cycle to generate more energy. This improves efficiency compared to the normal combined cycle process due to the higher-temperature steam produced by the gasification process.

Interconnection – an electric grid at a regional scale or larger that operates at a synchronized alternating current (AC) frequency, which allows for efficient transmission of power throughout the grid, connecting a large number of electricity generations and consumers and facilitating electricity market trading.

Intermittent renewable electricity – sources of renewable energy, such as wind and solar, that do not produce electricity consistently and cannot be directly controlled.

Interstate – connecting or involving different states.

Intraday balancing – managing changes in gas demand over a 24-hour period.

Intrastate – existing or occurring within the boundaries of a state.

Lateral Pipeline – delivers gas to or from a mainline.

Leakage – gas or related fluid migration or flow out of the storage system into the environment (subsurface or above ground). It is one type of loss of containment.

Levelized cost – the net present value of the unit-cost of electricity over the lifetime of a power-generating facility. This includes the initial capital costs and ongoing operation, fuel and maintenance costs.

Light/medium/heavy duty vehicles – three classifications of vehicles by weight for the purpose of emissions regulations.

Likelihood – probability per unit time (e.g., per year), per component, or quantitative or semi-quantitative chance (or expected frequency) of occurrence of a failure scenario.

Load balancing – the storage of excess electrical power during low demand periods to be released as demand rises.

Load-pocket balancer – a small local facility that stores and delivers natural gas to accommodate the limits on the ability to move large amounts of natural gas back and forth within a system and improve overall system balance.

Load centers – breaker or fuse boxes, which take electricity supplied by the utility or electric company and distribute it throughout the home.

Load serving entities – an industry term for an electric company. They are companies or organizations that supply load (electricity) to consumers.

Load-shifting – a technique of demand-side management, which involves moving the consumption of high wattage loads to different times within an hour or day or week.

Loss of containment (LOC) – unplanned release to the environment (subsurface or above ground) of gas or related fluid. LOC incidents refer to significant losses of containment of stored gas, i.e., significant enough that it warranted reporting.

Low-carbon gas – refers to alternative fuels, such as natural gas, which have lower carbon dioxide emissions when burned (compared to conventional petroleum fuels).

Low-carbon gas scenario – the scenario of GHG emissions reduction in California to meet 2030 and 2050 GHG emissions reduction goals, which relies heavily on low-carbon gas production, e.g. biomethane, SNG and/or hydrogen blended into pipelines.

Measured Depth (MD) – the length of the well. This may be larger than the depth of the well if the well is not vertical.

Methane – a chemical compound with the formula CH4 (one atom of carbon and 4 atoms of hydrogen). It is the main constituent of natural gas and is in a gaseous state under typical conditions for temperature and pressure.

Naphtha – a general term for any of the volatile, highly flammable liquid mixtures of hydrocarbons derived during the refining of crude oil, natural gas, coal tar, etc.

Natural gas – a naturally occurring gas mixture consisting primarily of methane. It is found in deep underground rock formations and formed when layers of decomposing plant and animal matter are exposed to intense heat and pressure under the surface of the Earth over millions of years.

Natural gas combined cycle plant – a power plant that uses a gas and a steam turbine together to produce more electricity from the same fuel. The waste heat from the gas turbine that burns natural gas is routed to make steam for a steam turbine to generate extra power.

Natural gas reforming – a production process that generates hydrogen from natural gas. The most common process is steam-methane reforming, in which high-temperature steam reacts with methane to produce hydrogen and carbon-monoxide.

Natural gas vehicles (NGV) – a vehicle that uses compressed natural gas or liquefied natural gas for energy.

Liquid natural gas (LNG) needle peakers – small local facilities that are built to meet very high demand for natural gas. These facilities typically chill and store the liquid natural gas and regasify it and add it to the pipeline when needed.

Non-Core Customers – include all cogeneration, regardless of load size, and those commercial customers with annual loads above 250,000 therms. 250,000 therms are approximately equal to an annual monthly average usage level of 20,800 therms.

Non-fossil electricity generation – the generation of electric power using non-fossil fuel sources, like hydropower, nuclear, wind, and solar.

NO_x emissions – nitric oxide and nitrogen dioxide gases, which are produced during the consumption of fuels (e.g., in car engines and power plants). These gases contribute to air pollution, specifically the formation of smog and acid rain.

Off-normal – condition characterized by deviation from standard operational or shut-in status, e.g., gas leakage in a system designed to contain gas, plug-in lines that are intended to transport gas, excessively high or low pressure in flowlines, tanks, well tubing or annuli.

Off-peak – refers to lower electrical power demand and generally discounted electricity prices during specific times.

Once-through-cooling (OTC) – a method of cooling power plants, where water is taken from a nearby source (e.g., river or lake) and circulated through pipes to absorb the heat from the steam in the power plant and then discharged back to the local source.

Overhang – amount of gas left at the border that California does not bring into pipelines.

Overpressure – fluid pressure above the hydrostatic pressure, e.g., as caused by injection.

Oxy-combustion – or oxy-fuel combustion, which is the process of burning a fuel using pure oxygen instead of air as the primary oxidant. Since the nitrogen component of air is not heated, fuel consumption is reduced and higher flame temperatures are possible.

Packer – a device inserted into a well that is then expanded (e.g., inflated) to seal the well. E.g., a packer is used to seal the A-Annulus from the reservoir while allowing the tubing to run through it to convey high-pressure fluids (liquids and gases).

Parabolic trough concentration designs – a design for a solar thermal energy collector that is straight in one dimension and curved as a parabola in the other two (like a trough) and lined with a mirror. The sunlight is then focused along the focal line, where there is often a tube, which contains a fluid that is heated to a high temperature to generate electricity.

Peak demand – the time period which represents the highest point of customer consumption of electricity.

Perfs (short for perforations) – holes or slots in well casing, tubing, or liner to connect the well to the reservoir fluids.

Photoelectrochemical – refers to the interaction of light with electrochemical systems. Photoelectrochemical cells (PECs) are solar cells that produce electrical energy or hydrogen in a process similar to water electrolysis.

Pipeline capacity – the quantity (volume) of oil or gas required to maintain a full pipeline.

Plant – in the context of a UGS facility, the plant is the part of the facility with surface infrastructure consisting of any one or all of components such as compressors, gas processing units, electricity generation units, or control room and/or operator office space.

Pool – see Hydrocarbon reservoir

Post-combustion capture – the process of collecting carbon dioxide (CO2) from the exhaust of a combustion process and absorbing it in a suitable solvent.

Power-to-gas (P2G) – load balancing technology that converts excess electricity into hydrogen and/or methane, typically for direct pipeline injection.

Pressure swing adsorption – a technology used to separate certain gas species from a mixture of gases by adsorbing the target gases onto a solid surface under high pressure.

Process – a long-term or slow change in the system relevant to performance. Corrosion of steel, cement degradation, or sand production are some examples of processes relevant to UGS performance.

Production – the primary extraction/delivery of fluid (liquid or gas) from a reservoir to the ground surface via a well for beneficial use (see also Withdrawal).

Pumped hydroelectric storage (PHES) – the storage of energy in the form of water in an upper reservoir, pumped from another reservoir at lower elevation. During periods of high electricity demand, power is generated by releasing the stored water through turbines. During periods of low demand, the upper reservoir is recharged by using lower-cost electricity from the grid to pump the water back to the upper reservoir.

Pure Hydrogen – gas that is made up of only hydrogen with no other impurities.

Ramping requirements – the speed at which backup energy might have to be supplied to the electrical grid.

Rate schedule "FT-H" – the cost per volume for hourly firm transportation service of natural gas.

Receipt point capacity – the amount of gas a utility can take away from the interstate pipelines at the California state line, can also be called take-away capacity.

Risk – likelihood (of failure scenario) multiplied by consequences (of failure scenario).

Risk analysis – process by which risks are assessed and managed including development and evaluation of failure scenarios, accident sequences, fault-trees, bow-tie diagrams, mitigation options and their comparative costs.

Risk assessment – systematic process of identifying, evaluating, and quantifying the risks involved in an activity or undertaking.

Risk endpoint – value (e.g., health, safety, containment, non-degradation) to be protected.

Seal – laterally extensive and low-permeability and/or high capillary-entry-pressure formation (e.g., clay shale or mudstone) above a storage reservoir capable of impeding upward migration of fluid. Synonymous with caprock.

Seismic hazard – likelihood that an earthquake will occur in a given location or along a given fault, within a given window of time, and with ground motion intensity exceeding a given threshold. Although the term hazard is used here, its meaning in this context is different from the standard use of the term hazard in risk assessment (see Hazard).

Seismic risk – risk (seismic hazard multiplied by consequences, e.g., collapse of building(s) in the area) of an earthquake in a given window of time.

Sequestration – the process of injecting carbon dioxide (CO2) captured from an industrial or energy-related source into deep subsurface rock formations for long-term storage.

Short-lived climate pollutants (SLCPs) – powerful climate forcers that have relatively short lifetimes in the atmosphere (a few days to a few decades). They include methane, hydrofluorocarbons (HFCs), and black carbon.

Shrinkage – extra gas that customers deliver to the pipeline to account for gas used to run compressors and gas that is lost to measurement discrepancies.

Skin factor – a measure of the increased resistance to flow in the formation around a well as observed by increased pressure drop in the well during production.

Slow-ramping – describes power plants and electricity generation facilities that take a long time to turn on and start generating power.

Solar thermal – describes a form of technology for harnessing solar energy to generate thermal energy or electrical energy.

Spud – to begin drilling a boring into the ground.

Straight line scenario – the scenario of greenhouse gas (GHG) emission reduction in California where the trajectory of GHG emissions reduction is a straight line between today's GHG levels and the 2030 or 2050 goal. This scenario relies on increased renewable electricity generation and building electrification to meet those goals.

Sub second electricity storage – electrical storage that is provided by flywheels or fast-response batteries for the purpose of frequency regulation in the electric grid.

Subsurface blowout – the uncontrolled flow of gas, liquids, or solids (or a mixture thereof) from a well into the subsurface environment.

Syngas – also called synthesis gas, is a fuel gas mixture consisting primarily of hydrogen, carbon monoxide, and carbon dioxide. It is used for electricity generation, fuel, and the production of hydrogen, ammonia and synthetic hydrocarbon fuels.

Synthetic natural gas (SNG) – a fuel gas that can be produced from fossil fuels, such as lignite coal, oil shale or biofuels. It can serve as a substitute for natural gas and is suitable for transmission in natural gas pipelines.

Take-away capacity – the amount of gas a utility can take away from the interstate pipelines at the California state line, can also be called take-away capacity.

Tariff – the pricing structure a utility charges a customer for gas or electricity consumption.

Temporal scope – the time period over which likely environmental effects may be experienced due to a proposed project or development.

Thermal gasification – the process of converting biomass into a combustible gas, volatiles, and ash in an enclosed reactor in the presence of an oxidizing agent.

Thermochemically – by means of a chemical reaction where there is the release or absorption of heat energy.

Therms – a unit of heat energy equal to 100,000 Btu. It is approximately the energy equivalent of burning 100 cubic feet (or 1 CCF) of natural gas.

Threat – a potential source of harm to humans, other animals, plants, environment, or infrastructure. Synonymous with hazard.

Title 20 – Appliance Efficiency Regulations, set California standards for energy consumption for both federally and non-federally regulated appliances.

Title 24 – California Building Standards Code, regulations that set standards for constructing buildings in California. Updated every three years.

Total Dissolved Solids (TDS) – the sum of the masses of salts and minerals dissolved in groundwater per unit volume of groundwater, e.g., in milligrams per unit volume of water (mg/L) although it is also often referred to as parts per million (ppm).

Tower concentration designs – a design for a solar thermal energy collector that uses an array of flat mirrors to focus the sun's rays upon a collector tower, where the focused rays are used to heat fluids to generate electricity.

Transmission capacity – the amount of electrical power that can be sent over a transmission line.

Transmissivity – a measure of flow resistance and capacity of a permeable pathway. Transmissivity can be thought of as pathway fluid conductivity multiplied by the minimum pathway dimension perpendicular to flow (i.e., the aperture of a fracture).

Tubing – pipe (typically made of steel as used in oil and gas wells) positioned with casing(s) to allow conveyance of fluids to/from the surface from/to a specific location in the subsurface.

Ultracapacitors – an energy storage technology that offers high power density, instant recharging and very long lifetimes. They play a role in delivering peak power and extending the lifespan of batteries in energy storage systems.

Underground Source of Drinking Water (USDW) – an aquifer or part of an aquifer that supplies any public water system, or contains a sufficient quantity of ground water to supply a public water system, and currently supplies drinking water for human consumption, or contains fewer than 10,000 mg/L of Total Dissolved Solids (TDS).

Utility-scale solar PV – a solar power facility that generates solar power and feeds it into the grid, supplying the utility with energy.

Vehicle-Grid Integration Roadmap – a high-level plan to enable electric vehicles to provide grid services while still meeting consumer driving needs.

Warren Alquist Act – a California state law that created the Energy Commission in 1974 and gave it authority to develop and maintain building energy efficiency standards for new buildings.

Water electrolysis – the separation of water into oxygen and hydrogen gas due to an electric current being passed through the water.

Well Cellar – a dug-out area lined with cement or large-diameter (6 ft/1.8 m) thin-wall pipe within which the well extends out of the ground. The casing spool and casing head reside within the well cellar. The depth of the cellar is such that the master valve of the Christmas tree is easy to reach from ground level (after http://www.glossary.oilfield.slb.com/Terms/c/cellar.aspx (accessed 7/25/17)).

Well workover – repair or stimulation of a well for improving production or injection function.

Western grid – the fragmented electric grid across western United States and parts of Canada and Mexico that is managed by multiple entities, including California ISO.

Wind generation capacity – the maximum electric output that can be produced from wind power generation.

Withdrawal – extraction/delivery of fluid (liquid or gas) from a storage reservoir to the ground surface via wells (see also Production).

Working capacity – quantity of gas that can be injected and withdrawn from the field. Excludes cushion gas.

Working gas – the volume of gas that is injected and withdrawn. The total volume of gas in a reservoir is the sum of the working gas and the cushion gas (base gas).

Appendix G

Review of Information Sources

This study was conducted as a synthesis of existing publically available data including the results of many currently on-going or recently completed relevant studies, protocols and proposed regulations. The quality of the assessment depended on the quality of the information and time available for the study. The study includes ant assessment of data adequacy and limitations posed by time constraints.

Our scientists cited a given reference in the report if it met all three of the following criteria:

1. Fit into one of the seven categories of admissible literature (described in a-g below).

    a. Published, peer-reviewed scientific papers.

    b. Government data and reports including analysis of available data from CPUC, DOGGR, and other publically available sources.

    c. Academic studies that are reviewed through a university process, textbooks, and papers from technical conferences.

    d. Studies generated by non-government organizations that are based on data, and draw traceable conclusions clearly supported by the data.

    e. Voluntary reporting from industry. This data is cited with the caveat that, as voluntary, there is no quality control on the accuracy or completeness of the data.

    f. Other relevant publications including reports and theses. We state the qualifications of the information used in the report.

    g. Additional authoritative sources including the expert opinion of the committee and scientific community.

2. Was relevant to the scope of the report.

3. Added substantive information to the report.

For this report, authors of the report reviewed many sources of public information, including some that are not easily accessible to all citizens, such as fee-based scientific journals. If a member of the public wishes to view a document referenced in the report, they may visit California Council on Science and Technology at 1130 K Street, Suite 280, Sacramento, CA 95814-3965. We cannot duplicate or electronically transmit copyright documents. Please make arrangements in advance by contacting CCST at (916) 492-0996.

Appendix H

California Council on Science and Technology Study Process

California Council on Science and Technology (CCST) studies are viewed as valuable and credible because of the organization's reputation for providing independent, objective, and nonpartisan advice with high standards of scientific and technical quality. Checks and balances are applied at every step in the study process to protect the integrity of the studies and to maintain public confidence in them.

Study Process Overview—Ensuring Independent, Objective Advice

For over 25 years, CCST has been advising California on issues of science and technology by leveraging exceptional talent and expertise.

CCST enlists the state's foremost scientists, engineers, health professionals, and other experts to address the scientific and technical aspects of society's most pressing problems.

CCST studies are funded by state agencies, foundations and other private sponsors. CCST provides independent advice; external sponsors have no control over the conduct of a study once the statement of task and budget are finalized. Authors and the Steering Committee gather information from many sources in public and private meetings but they carry out their deliberations in private in order to avoid political, special interest, and sponsor influence.

Stage 1: Defining the Study

Before the author and Steering Committee selection process begins, CCST staff and members work with sponsors to determine the specific set of questions to be addressed by the study in a formal "statement of task," as well as the duration and cost of the study. The statement of task defines and bounds the scope of the study, and it serves as the basis for determining the expertise and the balance of perspectives needed for the study authors, Steering Committee members, and peer reviewers.

The statement of task, work plan, and budget must be approved by CCST's Project Director in consultation with CCST leadership. This review sometimes results in changes to the proposed task and work plan. On occasion, it results in turning down studies that CCST believes are inappropriately framed or not within its purview.

Stage 2: Study Authors and Steering Committee (SC) Selection and Approval

Selection of appropriate authors and SC members, individually and collectively, is essential for the success of a study. All authors and SC members serve as individual experts, not as representatives of organizations or interest groups. Each expert is expected to contribute to the project on the basis of his or her own expertise and good judgment. The lead author(s) serves as an ex-officio, nonvoting member of the SC to ensure continued communication between the study authors and the SC. CCST sends nominations of experts to the Oversight Committee (made up of two CCST Board Members and an outside expert) for final approval after conducting a thorough balance and conflict of interest (COI) evaluation including an in-person discussion. Any issues raised in that discussion are investigated and addressed. Members of a SC are anonymous until this process is completed.

Careful steps are taken to convene SCs that meet the following criteria:

> **An appropriate range of expertise for the task**. The SC must include experts with the specific expertise and experience needed to address the study's statement of task. A major strength of CCST is the ability to bring together recognized experts from diverse disciplines and backgrounds who might not otherwise collaborate. These diverse groups are encouraged to conceive new ways of thinking about a problem.
>
> **A balance of perspectives**. Having the right expertise is not sufficient for success. It is also essential to evaluate the overall composition of the SC in terms of different experiences and perspectives. The goal is to ensure that the relevant points of view are, in CCST's judgment, reasonably balanced so that the SC can carry out its charge objectively and credibly.
>
> **Screened for conflicts of interest**. All provisional SC members are screened in writing and in a confidential group discussion about possible conflicts of interest. For this purpose, a "conflict of interest" means any financial or other interest which conflicts with the service of the individual because it could significantly impair the individual's objectivity or could create an unfair competitive advantage for any person or organization. The term "conflict of interest" means something more than individual bias. There must be an interest, ordinarily financial, that could be directly affected by the work of the SC. Except for those rare situations in which CCST determines that a conflict of interest is unavoidable and promptly and publicly discloses the conflict of interest, no individual can be appointed to serve (or continue to serve) on a SC used in the development of studies if the individual has a conflict of interest that is relevant to the functions to be performed.
>
> **Point of View is different from Conflict of Interest**. A point of view or bias is not necessarily a conflict of interest. SC members are expected to have points of view, and CCST attempts to balance these points of view in a way deemed appropriate for the task. SC members are asked to consider respectfully the viewpoints of

other members, to reflect their own views rather than be a representative of any organization, and to base their scientific findings and conclusions on the evidence. Each SC member has the right to issue a dissenting opinion to the study if he or she disagrees with the consensus of the other members.

Other considerations. Membership in CCST and previous involvement in CCST studies are taken into account in SC selection. The inclusion of women, minorities, and young professionals are additional considerations.

Specific steps in the SC selection and approval process are as follows:

CCST staff solicit an extensive number of suggestions for potential SC members from a wide range of sources, then recommend a slate of nominees. Nominees are reviewed and approved at several levels within CCST. A provisional slate is then approved by the Oversight Committee. Prior to approval, the provisional SC members complete background information and conflict-of-interest disclosure forms. The SC balance and conflict-of-interest discussion is held at the first SC meeting. Any conflicts of interest or issues of SC balance and expertise are investigated; changes to the SC are proposed and finalized. The Oversight Committee formally approves the SC. SC members continue to be screened for conflict of interest throughout the life of the committee.

CCST uses a similar approach as described above for SC development to identify study authors who have the appropriate expertise and availability to conduct the work necessary to complete the study. In addition to the SC, all authors, peer reviewers, and CCST staff are screened for COI.

Stage 3: Author and Steering Committee Meetings, Information Gathering, Deliberations, and Drafting the Study

Authors and the Steering Committee typically gather information through:

1. meetings;

2. submission of information by outside parties;

3. reviews of the scientific literature; and

4. investigations by the study authors and/or SC members and CCST staff.

In all cases, efforts are made to solicit input from individuals who have been directly involved in, or who have special knowledge of, the problem under consideration.

The authors shall draft the study and the SC shall draft findings and recommendations. The SC deliberates in meetings closed to the public in order to develop draft findings and recommendations free from outside influences. All analyses and drafts of the study remain confidential.

Stage 4: Report Review

As a final check on the quality and objectivity of the study, all CCST reports, whether products of studies, summaries of workshop proceedings, or other documents, must undergo a rigorous, independent external peer review by experts whose comments are provided anonymously to the authors and SC members. CCST recruits independent experts with a range of views and perspectives to review and comment on the draft report prepared by the authors and the SC.

The review process is structured to ensure that each report addresses its approved study charge, that the findings are supported by the scientific evidence and arguments presented, that the exposition and organization are effective, and that the report is impartial and objective.

The authors and the SC must respond to, but need not agree with, reviewer comments in a detailed "response to review" that is examined by one or more independent "report monitor(s)" responsible for ensuring that the report review criteria have been satisfied. After all SC members and appropriate CCST officials have signed off on the final report, it is transmitted to the sponsor of the study and the sponsor can release it to the public. Sponsors are not given an opportunity to suggest changes in reports. All reviewer comments and SC deliberations remain confidential. The names and affiliations of the report reviewers are made public when the report is released.

Appendix I

Expert Oversight and Review

Oversight Committee:

- **Richard C. Flagan**, California Institute of Technology
- **John C. Hemminger**, University of California Irvine
- **Robert F. Sawyer**, University of California, Berkeley

Report Monitor:

- **Robert F. Sawyer**, University of California, Berkeley

Expert Reviewers:

- **Aaron S. Bernstein**, Harvard University
- **Nancy S. Brodsky**, Sandia National Laboratories
- **Linda R. Cohen**, University of California, Irvine
- **Rosa Dominguez-Faus**, University of California, Davis
- **James L. Gooding**, Black & VEATCH
- **William Hoyle**, *former* U.S. Chemical Safety and Hazard Investigation Board
- **Gary B. Hughes**, California Polytechnic State University
- **Lisa M. McKenzie**, University of Colorado Denver
- **Michal C. Moore**, Cornell University
- **Joseph P. Morris**, Lawrence Livermore National Laboratory
- **Phillip G. Nidd**, Dynamic Risk Assessment Systems, Inc.
- **Franklin M. Orr**, Stanford University

- **Snuller Price**, Energy and Environmental Economics, Inc.
- **Kevin Woodruff**, Woodruff Expert Services

Appendix J

Unit Conversion Table

1	Oil Barrel (42 gallons)	=	0.158987	Cubic Meters (m^3)
1	Cubic Foot (cf)	=	0.02831685	Cubic Meters (m^3)
1	Cubic Foot per Day (cfd)	=	0.02831685	Cubic Meters per Day (cmd)
1	British Thermal Unit (Btu)	=	1055	Joules (J)
1	MMBtu	=	1000000	British Thermal Units (Btu)
1	Mcf	=	1000	Cubic Feet (cf)
1	MMcf	=	1000000	Cubic Feet (cf)
1	MMcfd	=	1000000	Cubic Feet per Day (cfd)
1	MMscf	=	1000000	Standard Cubic Feet (scf)
1	Therm (th)	=	100000	British Thermal Units (Btu)
1	Dekatherm (dth)	=	1000000	British Thermal Units (Btu)
1	Watt (W)	=	1	Joule per second (J/s)
1	Kilowatt (kW)	=	1000	Watts (W)
1	Megawatt (MW)	=	1000000	Watts (W)
1	Gigawatt (GW)	=	1×10^9	Watts (W)
1	Kilowatt hour (kWh)	=	3.6×10^6	Joules (J)
1	Megawatt hour (MWh)	=	1000	Kilowatt hours (kWh)
1	Pound (lb)	=	0.45359237	Kilogram (kg)
1	Foot (ft)	=	0.3048	Meters (m)
1	Standard Cubic Foot (scf)[1]	=	1020	British Thermal Units (Btu)
1	Pound per Square Inch (psi)	=	6894.76	Pascals (Pa)
1	US Ton	=	907.185	Kilograms (kg)

1 A standard cubic foot (scf) corresponds to 1 cubic foot of gas at 60 °F (15.6 °C) and 14.73 pounds per square inch absolute (psia)

Appendix K

Southern California Natural Gas Infrastructure Model

1. Problem Statement

As part of the CCST study of natural gas storage in California, Los Alamos National Laboratory (LANL) was tasked with creating a dynamic physics based model of the Southern California Natural Gas system infrastructure. GRAIL was used to examine how gas storage facility performance problems impact gas delivery and the consequences for electricity supply. Although GRAIL is still in development stages, GRAIL was used to simulate a scenario in which the Aliso Canyon storage facility was inoperative.

The simulation results show the system had minimal load shedding at natural gas fired generators and pressures remained within operating norms. This is just one scenario that looks at the role gas storage plays in gas supply reliability and in meeting the gas demand for electricity supply. Many more scenarios should be run to further understand the relationship between gas storage and electricity supply. With further research and funding, GRAIL can be used to examine other storage scenarios to identify operational changes that could optimize gas delivery to natural gas fired electric generation facilities. Along with this study, additional studies will be needed to further asses the viability of underground natural gas storage in California.

2. Gas Reliability Analysis Integrated Library (GRAIL)

LANL has developed a preliminary physics-based model to address several pipeline analysis challenges through the development of the Gas Reliability Analysis Integrated Library (GRAIL). Within GRAIL, LANL has made several recent advances to optimization techniques and control system modeling to provide computationally tractable yet accurate and scalable methods for steady-state optimization (Misra, et al., 2015) (Rios-Mercado & Borraz-Sanchez, 2015), dynamic simulation (Zlotnik, Dyachenko, Backhaus, & Chertkov, 2015) (Dyachenko, Zlotnik, Chertkov, & Korotkevich), and predictive optimal control (Mak, Van Hentenryck, Zlotnik, Bent, & Hijazi, Efficient Dynamic Compressor Optimization in Natural Gas Transmission Systems, 2016) (Zlotnik, Chertkov, & Backhaus, Optimal Control of Transient Flow in Natural Gas Networks, 2015) of gas transport under uncertainty. These advances enable efficient computational methods to model decision processes and physical evolution of large-scale pipelines subject to engineering constraints. GRAIL algorithms can be extended to model pipeline flow scheduling, component-level actions, and corrections by automatic supervisory controls and human operators in reaction to disruptions. GRAIL employs Minimum Load Shedding (MLS) optimization to predict selected aspects of the natural gas infrastructure system state, specifically relating to operations during capacity operations.

LANL is developing the GRAIL algorithms for scalable gas flow modeling and optimization for the Department of Homeland Security and for industry practitioners via the Advanced Research Projects Agency-Energy. This set of algorithms consists of three components that perform (i) steady-state optimization, (ii) dynamic simulation, and (iii) dynamic optimization of large-scale natural gas transmission pipeline flows. Each component requires a static network model that describes the structure of the network and engineering constraints on pressure and compressor horsepower. Component (i) has inputs of maximum and minimum supplies and loads (constant scalars) at all network nodes and a prioritization (by numerical values) of importance of the loads. Component (i) output is the steady-state flow on each pipe that delivers gas to loads according to importance by node. Component (ii) requires given flow in or out of each node as time-series over the simulation horizon. Component (ii) output is a time-series of flows and pressures throughout the pipeline system that result from the given time-varying loads. Component (iii) requires the maximum and minimum supplies and loads at all network nodes and a prioritization of the loads (as time-series over the optimization horizon, e.g. 24 hours). Component (iii) output is a time-series of flows and pressures throughout the pipeline system that allocates gas to loads dynamically according to importance by node and time. Component (ii) can be used to simulate the second-order effects of network damage, and components (i) and (iii) can be used to approximate system operator behavior to compensate for network damage.

The GRAIL software is implemented in Julia (Julia, 2017), a free and open-source programming language for scientific computing with capabilities similar to Matlab. Through Julia, GRAIL is utilizes the free an open-source solver Interior Point Optimizer (IPOPT) (Github-coin-or, n.d.), a state-of-the-art code for solving large-scale nonlinear optimization problems. A key advantage of building GRAIL exclusively on open-source software is that there are no license restrictions. This allows GRAIL to be easily packaged as a containerized executable (e.g. via Docker, Kubernetes), which can be run locally or deployed in a scalable High-Performance Cloud environment. Combining containerization of open-source codes with infrastructure as a service (IaaS) (e.g. Amazon Web Services) enables a nearly endless number of GRAIL analyses to be done in parallel at minimal computational cost.

A scenario identical to the scenario in the Aliso Canyon Summer 2017 Assessment was created, the simulation was run for a 24-hour period, and yielded a feasible solution for all network points. The feasible solution, a time series for every network point and edge, had minimal load shedding (0 to 0.6 MMcfd) and pressures within a normal range of 475 to 675 psig. These results are a step in the right direction towards validating the GRAIL model against actual conditions in the natural gas system. For full validation, the hourly pressure and flow data for all metered points in the system are needed but CCST does not have access to that data. Additionally, now with line 4000 outage, it would be interesting to input this new scenario (with specific mitigations detailed by SoCalGas) to see if GRAIL can find a feasible solution and to look at the geospatial pressure differentials in the system. As GRAIL matures and the visualization becomes more sophisticated in near real time, the benefits will become more clear.

2.1. Data

The GRAIL capability uses inputs from three different sources:

Homeland Security Infrastructure Program (HSIP) Gold 2015 (Homeland Security Infrastructure Program, n.d.) is a geospatial database inventory of infrastructure assets assembled by NGA in partnership with the Department of Homeland Security (DHS). The database is subject to the handling and distribution rules for "Unclassified For Official Use Only" due to licensing and sharing restrictions set forth by the data source entities. HSIP Gold provides geolocations for nodes (compressor stations, interconnects, natural gas fueled generators, receipt/delivery points) and edges (pipelines). Geolocation is important in determining the distance between nodes in the pipeline.

The Federal Energy Regulatory Commission (FERC) 567 data provides pressure information for interconnects, compressor stations, receipt/delivery points as well as average daily delivery amounts at each meter station. The FERC 567 data is considered Critical Energy Infrastructure Information (CEII) and is protected from disclosure with "non-disclosure agreements" (NDA).

Electronic Bulletin Boards (EBB), such as the SoCalGas ENVOY Informational Postings website (Sempra - SoCalGas ENVOY, n.d.), provide open source data on operating capacities and scheduled deliveries for each receipt/delivery point.

Combining data from several sources with varying quality requires a detailed roadmap. The following section and table provides that roadmap.

2.1.1 Inputs

Table 1 shows the data inputs mapped to the GRAIL model variables.

Table 1. Data Inputs Mapped to GRAIL Model Variables

System Component	Network Variable Type	Attribute Required from Source	Mapped GRAIL Model Variable	Units	Source
Compressor	Node connecting elements	Latitude, Longitude	Latitude, Longitude	Decimal Degrees	HSIP Gold 2015
	Node connecting elements	Design Suction Pressure	Cmin (minimum compressor ratio)	Psig	FERC 567
	Node connecting elements	Design Discharge Pressure	Cmax (maximum compressor ratio)	Psig	FERC 567
	Node connecting elements	Rated Horsepower	Hpmax (max horsepower)	HP	FERC 567
Pipeline	Edge	Latitude, Longitude	From Node	Decimal Degrees	HSIP Gold 2015
	Edge	Latitude, Longitude	To Node	Decimal Degrees	HSIP Gold 2015
	Edge	Length	Length	Miles	HSIP Gold 2015
	Edge	Diameter	Diameter	Inches	HSIP Gold 2015
	Edge	MAOP (maximum allowable operating pressure)	Pmax (maximum pressure for nodes and pipelines)	Psig	FERC 567
	Edge	Friction Factor	Friction Factor	Dimensionless	Diameter from HSIP Gold 2015 used in Friction Factor formula Assumed values if missing
Receipt/Delivery Points	Nodes	Latitude, Longitude	Latitude, Longitude	Decimal Degrees	HSIP Gold 2015
	Nodes	Maximum Daily Delivery	Qmax (maximum volume)	MDth/day	FERC 567
	Nodes	Operating Capacity	Qmax (maximum volume)	MMBtu=~Mcf	EBB Nominations
	Nodes	Scheduled Flow	Q (volume)	MMBtu=~Mcf	EBB Nominations
Interconnects	Nodes	Latitude, Longitude	Latitude, Longitude	Decimal Degrees	HSIP Gold 2015
	Nodes	Normal Pressure	P (pressure)	Psig	FERC 567
	Nodes	Scheduled Flow	Q (volume)	MMBtu=~Mcf	EBB Nominations
Natural Gas Fueled Generators	Nodes	Latitude, Longitude	Latitude, Longitude	Decimal Degrees	HSIP Gold 2015

2.1.2. Outputs

Given a Java Script Object Notation (JSON) gas network data file and 24 hours of injection and withdrawal data, and an arbitrary change to the network, the GRAIL model can be used to estimate the minimum reduction of withdrawal (load shed) to ensure gas flow feasibility while adhering to standard operating constraints of pressure and compressor limits. Outputs for the GRAIL model are: mass flux, density, nominations, desired withdrawal, achieved withdrawal, amount shed and compressor ratios at given nodes in the network.

3. Specific formulation of the scenario for the CCST Southern California Natural Gas Infrastructure Model

Given a gas network data file (JSON based network format) and 24 hours of injection and withdrawal data, and an arbitrary damage to the network, GRAIL can determine the minimum reduction of withdrawal (load shed) to ensure gas flow feasibility while adhering to standard operating constraints of pressure and compressor limits. The following sections describe the inputs into the GRAIL model.

3.3.1. Characterization of the Southern California Natural Gas Infrastructure Model for Core Deliveries, Generator Deliveries, Receipt Points (Pipeline), Receipt Points (Storage Withdrawals)

Each natural gas delivery point in the GRAIL model must be coded as sheddable or non-sheddable load. For the Southern California Natural Gas Infrastructure model the natural gas fired electric generators are the only sheddable load points. Core delivery is a term used to define natural gas deliveries to residential and commercial customers and is not allowed to be interrupted in the GRAIL model.

3.3.1.1. Core Deliveries

Natural gas deliveries to receipt points in the Southern California Natural Gas Infrastructure Model were categorized as either: Core Delivery (residential, commercial) or Generator Delivery (for Natural Gas fired generators). Core Delivery was further delineated into LA Basin Core delivery and San Diego Core delivery with the values based on population. Total core gas load was approximately 1437 MMcfd from the Aliso Canyon Risk Assessment Technical Report. 73% of total core delivery was sent to the LA Basin and 26% of the total core delivery was sent to the San Diego area. A flat 24 hour delivery profile was used due to the absence of actual core delivery hourly profile data.

3.3.1.2. Gas deliveries to Natural Gas fired generators

Generator natural gas delivery hourly profiles were estimated for the following generators based on their capacities found in the HSIP 2015 database and the U.S. Energy Information Administration (EIA) 860 database of Operable Generating Units in the United States by State and Energy Source (U.S. Energy Information Administration, n.d.). The hourly generator demand profiles were interpolated using the total hourly electric generation demand profile from the Aliso Canyon Risk Assessment Technical Report, Summer 2017 Assessment (Commission, 2017). Table 2 lists the natural gas electric generators used in the GRAIL simulation of the Southern California natural gas infrastructure model along with their estimated peak hour gas usage and megawatt capacity. The peak hour gas demand represents the 4:00pm value in the hourly profile. This list is based on data available from sources listed in Table 1 and may not include all natural gas fired generators in the Southern California area. Figure 1 shows the hourly demand profiles of each generator in MMcfd.

Table 2. Estimated electric generator demand for natural gas interpolated using the total hourly electric generation demand profile from the aliso canyon risk assessment technical report, summer 2017 assessment. peak hour mmcfd represents the 4:00pm value in the interpolated hourly profile.

Generator	Peak hour MMcfd	MW
AES Alamitos LLC	362	1970
Haynes 1	317	1724
Ormond Beach 1	296	1612
Redondo Beach 5	247	1343
Mountainview CC 3a	204	1108
Encina	174	871
CPV Sentinel Energy Project	156	850
Inland Empire Energy 1	150	819
Scattergood CC	147	803
Otay Mesa	129	686
Elk Hills	114	623
Sunrise Power Co LLC	111	605
Etiwanda 3	122	600
Mandalay 1	105	574
Valley (CA) 1A	105	573
Palomar	101	559
El Segundo 5a	96	526
Walnut Creek Egy 1	92	500
Harbor CC 2	85	466
Huntington Beach 2	83	452
Watson Cogen 1a	74	405
El Centro 4	64	350
Magnolia Repower 1	60	328
Kern River Cogeneration	55	300
Sycamore Cogeneration	55	300

Generator	Peak hour MMcfd	MW
Grayson 4	53	288
Long Beach Generatio GT1	47	260
Midway Sunset Cogeneration Co	43	234
Glenarm GT 1	37	203
Canyon Power Project	36	200
Riverside Energy Res 1	36	196
Chevron El Segundo Refinery	33	183
Indigo Energy 1	27	149
Olive 1	25	139
Malburg 1a	25	138
Niland GT1	22	121
Harbor CGCC 1	19	107

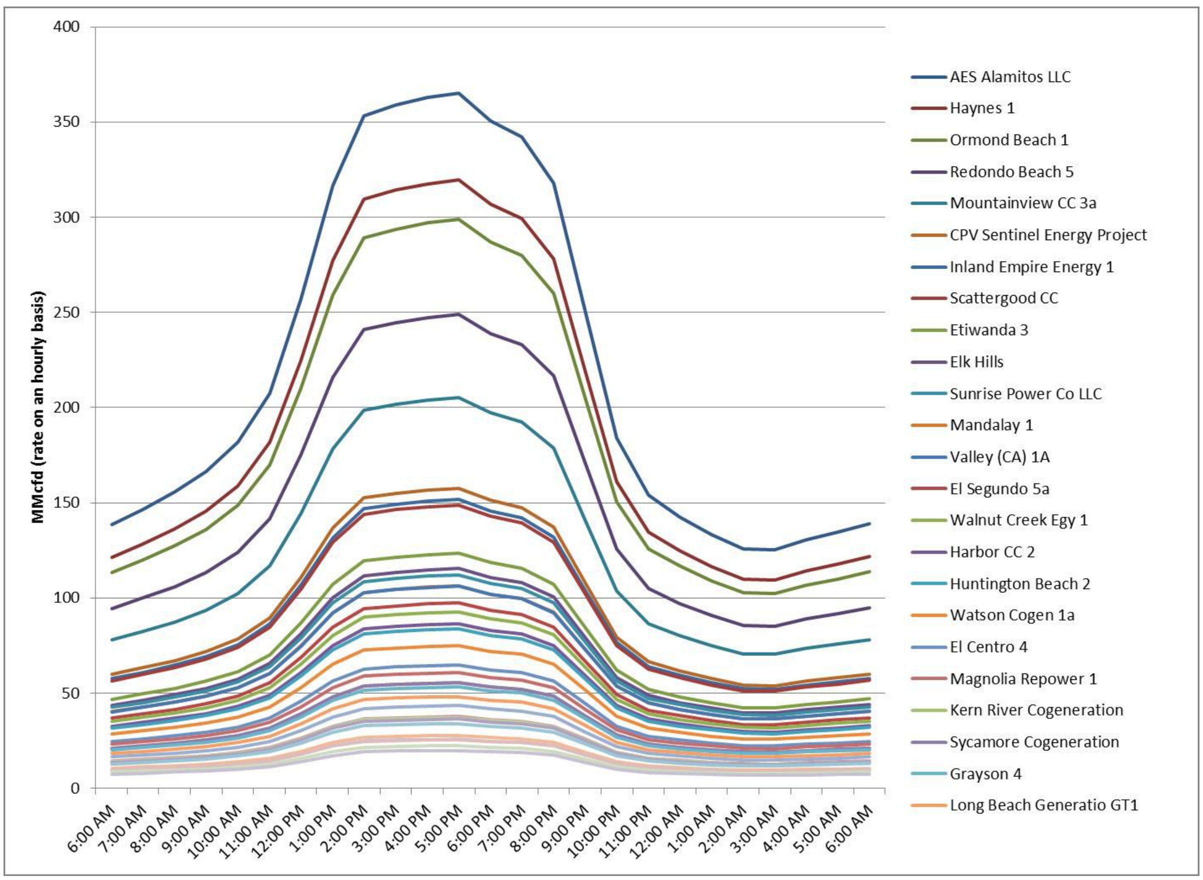

Figure 1. Hourly natural gas consumption profiles for LA basin and San Diego generators interpolated using the total hourly electric generation demand profile from the aliso canyon risk assessment technical report, summer 2017 assessment.

3.3.1.3. Receipt points (pipeline)

Natural gas deliveries to major receipt points were fixed in the GRAIL model using the values in Table 3. Hourly data for the receipt points was not available on the ENVOY website. A flat delivery profile was used for each receipt point. The values of incoming gas supplies were taken from the Aliso Canyon Risk Assessment Technical Report, Summer 2017 Assessment. Total flowing supplies are 3185 MMcfd.

Table 3. Receipt points (MMcfd)

Receipt Point	MMcfd
Line 85	60
Kramer Junction	550
Topock	0 (Line 3000 outage)
El Paso – Ehrenberg1	505
El Paso – Ehrenberg2	505
SoCalGas North Needles	800
Wheeler Ridge	765

3.3.1.4. Receipt points (storage withdrawals)

LANL modeled storage withdrawals from Aliso Canyon, Playa Del Rey, La Goleta and Honor Rancho as specified in the Aliso Canyon Risk Assessment Technical Report, Summer 2017 Assessment. Figure 2 shows the withdrawal profiles for each storage field. Aliso Canyon is modeled with zero withdrawals while the remaining 3 fields have various positive withdrawals during the course of the day.

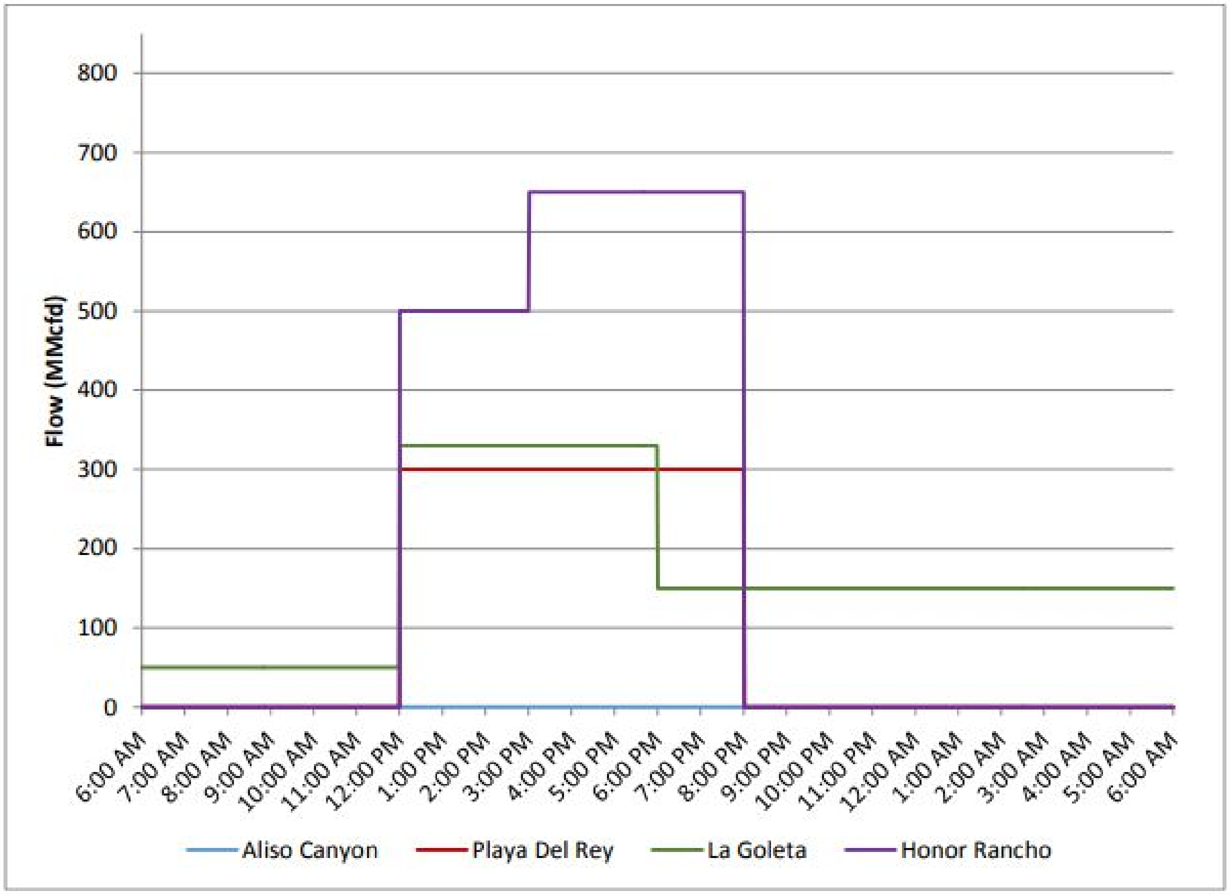

Figure 2. Storage withdrawal hourly profiles

3.3.2. Formulation for scenario inputs to the GRAIL model

The following defines how the core delivery inputs and the electric generator delivery inputs in the GRAIL model were calculated. The following are not the hydraulic modeling equations for GRAIL but rather the equations for calculating the scenario inputs.

Let D_i^c denote the Core delivery of natural gas in MMcfh for all i, and let D_i^{gen} denote the generator I delivery of natural gas in MMcfh. The total consumption of natural gas for electric generation can be written as $D_0^{gen} = \sum D_i^{gen}$ and assuming proportional consumption of natural gas based on MW capacity of each generator (assuming an equal heat rating for all generators) the individual generator consumption of natural gas can be calculated as (1.1).

$$D_i^{gen}(t) = \frac{P_i^{gen}}{\sum P_i^{gen}} * D_0^{gen}(t)$$

Letting $S^{PDR}(t), S^{G}(t), S^{HR}(t), S^{AC}(t)$ denote the storage withdrawals from Playa del Rey, Goleta, Honor Rancho, and Aliso Canyon and also allowing α_{LA} to represent the proportion of core load attributed to the LA Basin and $(1-\alpha_{LA})$ the core load attributed to the San Diego area, the Total LA Basin Load can be calculated as (1.2).

$$D^{LA}(t) = \sum_{i \in LA} D_i^{gen}(t) + \alpha_{LA} D_0^{c}(t) - S^{PDR}(t)$$

Where S^{PDR} are injections to Playa del Rey. And equivalently the Total Load in San Diego as (1.3).

$$D^{SD}(t) = \sum_{i \in SD} D_i^{gen}(t) + (1-\alpha_{LA}) D_0^{c}$$

Each delivery point is coded in the GRAIL model as either sheddable load or non-sheddable load. The model allows for load shedding only at the generator delivery points.

3.3.3. Results

Given the above scenario inputs for all receipt/delivery points in the Southern California Natural Gas Infrastructure Model, the GRAIL simulation was run with the following range of outputs in Table 4.

Table 4. Results for the southern california natural gas infrastructure model

Output Variable	Range of Values Estimated: Limit Case with 3 Slack nodes
Density (kg/s-1 m-2)	24-32
Nominations (MMcfd)	0-800 (hourly)
Desired Withdrawals (MMcfd)	0-800 (hourly)
Achieved Withdrawals (MMcfd)	0-800 (hourly)
Amount Load Shed (MMcfd)	0-0.6 (hourly)
Mass Flux (kg/s*m^2)	-4000 to +4000
Pipe Pressures (psig)	475-675
Compressor Ratios	1.0 – 1.35

Modeled pressures in the LA Basin ranged from 475-550 psig; pressures outside of the basin were higher ranging from 550-700 psig. The amount of load shed required to solve the model was small and ranged from 0-0.6 MMcfd on an hourly basis.

3.3.4. Visualization

LANL created a Leaflet (Leaflet - a JavaScript library for interactive maps, n.d.) application for viewing the Southern California Natural Gas Infrastructure Model results from the GRAIL code. Figure 3 displays a sample user interface to the model. The user can investigate mass flux, density, nominations, desired withdrawal, achieved withdrawal, amount shed and compressor ratios at given nodes in the network.

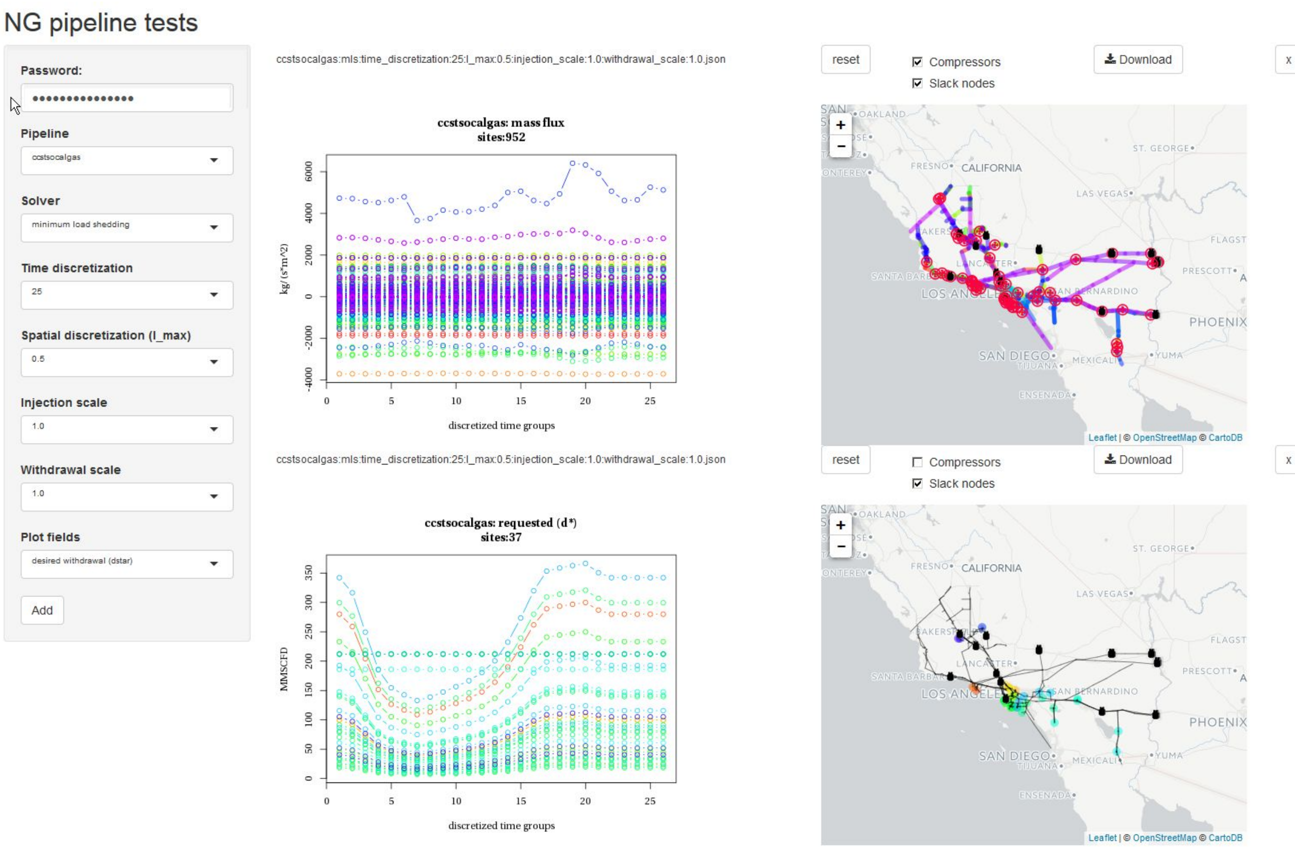

Figure 3. Sample user interface for the southern california Natural gas infrastructure model

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Appendix L

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LONG-TERM VIABILITY OF UNDERGROUND NATURAL GAS STORAGE IN CALIFORNIA: AN INDEPENDENT REVIEW OF SCIENTIFIC AND TECHNICAL INFORMATION
(FULL REPORT)

California Council on Science and Technology • January 2018