County of Ventura
Planning Commission Hearing
PL21-0099 and PL21-0100
Exhibit 8a – Footnotes cited in Exhibit 8
not otherwise included in Attachment A

3. Los Angeles County Planning Report to the Regional Planning Commission May 26, 2022.

4. Los Angeles County Regional Planning Commission Minutes, June 8, 2022.

14. CalGEM Idle Well Program Report

21. Jacqueline S. Ho, Jhih-Shyan Shil, Lucija A. Muehlenbachs, Clayton Munnings, and Alan J. Krupnick. 2018. Managing Environmental Liability: An Evaluation of Bonding Requirements for Oil and Gas Wells in the United States. Environ.Sci.Technol.2018, 52, 3908-3916.

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24. City of Los Angeles. 2018. Review of City of Los Angeles' Oil and Gas Drilling Sites. Report from the City Controller to the Mayor and City Council.

28. Office of Senate Floor Analyses. 2021-2022. Senate Third Reading Packet. Wednesday, May 26, 2021
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33. Intergovernmental Panel on Climate Change (IPCC). 2021. Climate Change 2021. The Physical Science Basis, Summary for Policymakers.

34. Caltrans, 2019. List of eligible and officially designated State Scenic Highways.
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Amy J. Bodek, AICP
Director of Regional Planning
Dennis Slavin
Chief Deputy Director,
Regional Planning

REPORT TO THE REGIONAL PLANNING COMMISSION

DATE ISSUED:	5/26/2022		
MEETING DATE:	6/8/2022	AGENDA ITEM:	5
PROJECT NUMBER:	PRJ2020-000246		
PROJECT NAME:	Oil Well Ordinance		
PLAN NUMBER(S):	RPPL2020000624		
SUPERVISORIAL DISTRICT:	1-5		
PROJECT LOCATION:	Countywide		
PROJECT PLANNER:	Adrienne Ng, Regional Planner ordinance@planning.lacounty.gov		

RECOMMENDATION

The Department of Regional Planning staff ("staff") recommends that the Regional Planning Commission (Commission) adopt the attached resolution recommending approval to the County of Los Angeles Board of Supervisors of the Oil Well Ordinance, Plan No. RPPL2020000624.

Staff recommends the following motion:

I MOVE THAT THE REGIONAL PLANNING COMMISSION CLOSE THE PUBLIC HEARING AND FIND THAT THE EXEMPTIONS QUALIFY PURSUANT TO STATE AND LOCAL CEQA GUIDELINES.

I ALSO MOVE THAT THE REGIONAL PLANNING COMMISSION ADOPT THE ATTACHED RESOLUTION RECOMMENDING APPROVAL TO THE COUNTY OF LOS ANGELES BOARD OF SUPERVISORS OF THE OIL WELL ORDINANCE, PLAN NO. RPPL2020000624.

PROJECT DESCRIPTION

A. Summary

Plan Number RPPL2020000624 is the Oil Well Ordinance (Ordinance), a project that amends Title 22 (Planning and Zoning) of the Los Angeles County Code to prohibit new oil wells and production facilities, designate existing oil wells and production facilities as nonconforming due to use, and establish consistent regulations for existing oil wells and production facilities during the amortization period. The Ordinance applies to the unincorporated areas of Los Angeles County, except for the Baldwin Hills Community Standards District, areas designated as a specific plan, and uses operating under a valid discretionary permit. The Ordinance (Exhibit A), Board Resolution (Exhibit B), and Notice of Exemption (Exhibit C) are attached to this report.

B. Background

On September 15, 2021, the County of Los Angeles Board of Supervisors (Board) approved a motion titled "Protecting Communities Near Oil and Gas Drilling Operations in Los Angeles County." The motion directs the Department of Regional Planning (Department) to: “prohibit all new oil and gas extraction wells in all zones, including those allowed or planned for under existing discretionary permits, and designate all existing oil and gas extraction activities, including those allowed or planned for under existing discretionary permits, as legal nonconforming uses in all zones.” The Ordinance implements the Board’s vision to prioritize and protect the public health, safety, and welfare of residents living near oil wells and begin the process of a just transition away from fossil fuels and decarbonization of the economy.

Also, the Board approved two related motions on September 15, 2021 titled: “Developing an Oil Well Cleanup Pilot Program for Los Angeles County” and “Developing a Comprehensive Strategy for a Just Transition Away from Fossil Fuels for Los Angeles County.” The three motions assigned several County agencies, including the Office of Oil and Gas at Public Works, Department of Public Health, Fire Department, and the Chief Sustainability Office, to work on these directives.

Prior to September 15, 2021, staff produced a draft ordinance responding to an earlier Board motion from March 29, 2016: “Proactive Planning and Enforcement of Oil and Gas Facilities Operating in Unincorporated Los Angeles County.” The September 15, 2021 motions supersede the March 29, 2016 motion. A summary of the efforts to address the March 29, 2016 motion is attached to this report for your Commission’s information (Exhibit E).

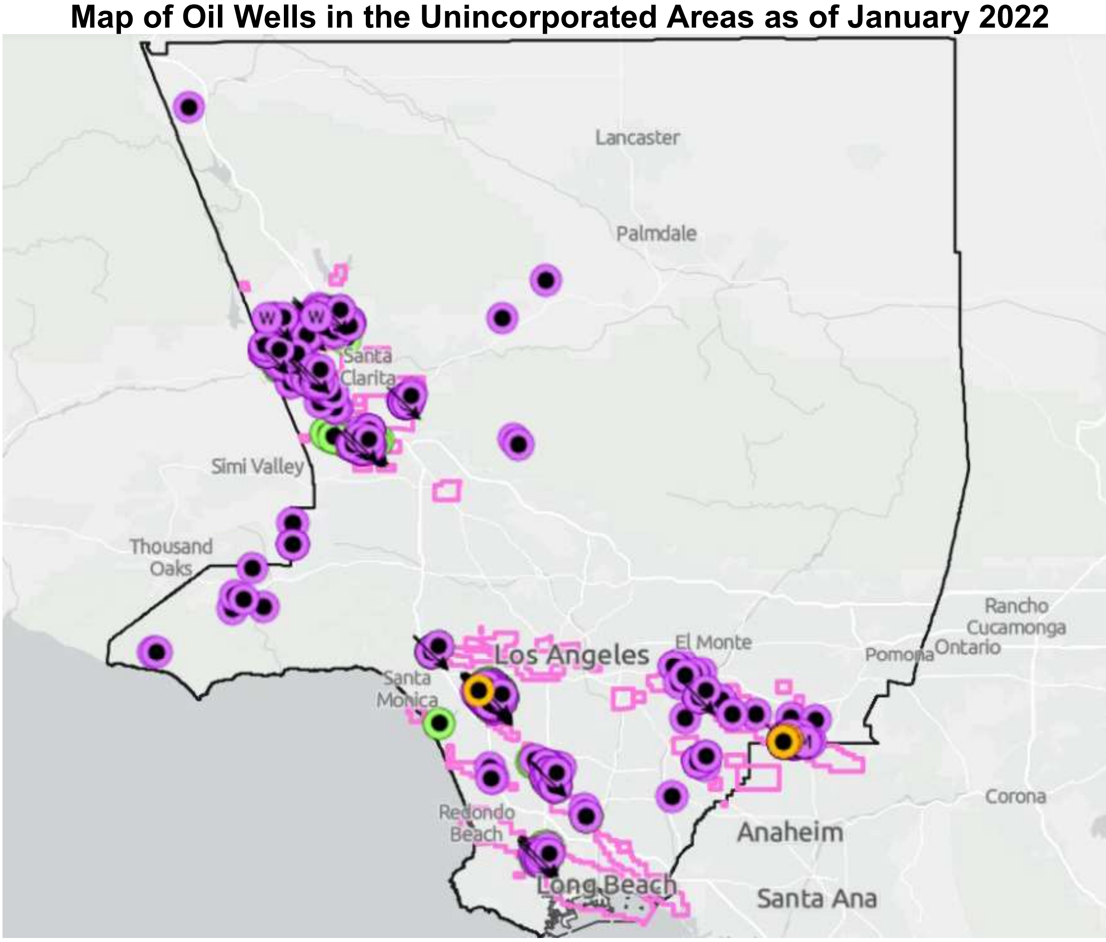
C. Location

According to CalGEM data from January 2022, there are 1,547 active or idle oil wells in the unincorporated areas of Los Angeles County. The Ordinance affects approximately 473 existing oil wells. The remaining 1,074 oil wells are within the Baldwin Hills Community Standards District, in an area designated as a specific plan, or are operating under a valid discretionary permit. The number and location of oil wells in the unincorporated areas are summarized below:

Oil Wells in the Unincorporated Areas (January 2022)						
			Oil Wells to be Addressed Separately From This Ordinance[1]			
Supervisorial District	Total Wells in the Unincorporated Areas	**Affected by the Ordinance**	Specific Plan	Discretionary Permit	Baldwin Hills Community Standards District	New – Permit for drilling issued by CalGEM
1	91	**16**	-	75	-	8
2	1006	**92**	2	57	855	1
3	26	**26**	-	-	-	-
4	30	**30**	-	-	-	-
5	394	**309**	55	30	-	-
All Districts	1547	**473**	57	162	855	9

1. The Ordinance does not apply to the Baldwin Hills Community Standards District, areas designated as a specific plan, or uses operating under a valid discretionary permit. DRP will address these in future efforts.

Map of Oil Wells in the Unincorporated Areas as of January 2022



D. Major Elements and Key Components

The Ordinance has three major elements and key components:

Prohibit New Oil Wells and Production Facilities
The Ordinance prohibits new oil wells and production facilities in 33 zones in Title 22 by adding "oil wells and production facilities" as a use "not permitted." The Ordinance also prohibits new oil wells and production facilities by amending the East Los Angeles Community Standards District and the Florence-Firestone Community Standards District to remove "oil wells and appurtenances, to the same extent and under all of the same conditions as permitted in Zone A-2" from the list of uses allowed in Zone M-1.

Designate Existing Oil Wells and Production Facilities as Nonconforming Due to Use
By adding "oil wells and production facilities" as a use "not permitted" in Title 22, the Ordinance designates existing, legally established oil wells and production facilities as nonconforming due to use. Chapter 22.172 (Nonconforming Uses, Buildings and Structures) contains regulations for the continuation, addition, repair, and termination of status for nonconforming uses. According to Sections 22.172.050.B and 22.172.050.B.1.f, nonconforming uses shall be discontinued and removed from their sites within 20 years of becoming nonconforming.

Establish Regulations for Existing Oil Wells and Production Facilities
The Ordinance adds consistent regulations to Title 22 for existing oil wells and production facilities, including: well and site signage, comment and complaint log, requirements for site maintenance, bonds for existing wells, and standards for well plugging and abandonment and restoration. These regulations ensure that existing oil wells and production facilities operate under a consistent set of development and performance standards and increase transparency in operations until the uses are discontinued and removed.

The Ordinance specifies a schedule for the effective date for regulations. Regulations for site maintenance, well plugging and abandonment, and restoration become effective on the date the Ordinance becomes effective. Regulations for well and site signage and the comment and complaint log become effective one year after the Ordinance goes into effect. Regulations for bonds become effective two years after the Ordinance goes into effect.

E. General Plan Consistency

The Ordinance is consistent with and supportive of the goals, policies, and principles of the General Plan, including:

- Policy LU 7.1: Reduce and mitigate the impacts of incompatible land uses, where feasible, using buffers and other design techniques.
- Policy LU 7.8: Promote environmental justice in the areas bearing disproportionate impacts from stationary pollution sources.
- Policy LU 9.1: Promote community health for all neighborhoods.
- Policy LU 9.4: Encourage patterns of development that protect the health of sensitive receptors.

F. Regulatory Agencies and Regulations

The Department and Title 22 are responsible for land use and zoning regulations in the unincorporated areas of Los Angeles County. In addition, there are numerous federal, state, regional, and local agencies that regulate oil wells and production facilities in California and in Los Angeles County. A summary of regulatory agencies and regulations is attached to this report for your Commission's information (Exhibit F).

G. Amendment to Title 12

Staff collaborated with the Department of Public Health on an amendment to Title 12 (Environmental Protection). The amendment to Title 12 removes the exception for oil wells and production facilities from the County's noise and vibration regulations. The amendment to Title 12 does not require action by your Commission and is attached to this report for your Commission's information (Exhibit D).

ENVIRONMENTAL ANALYSIS

The project (Ordinance) is exempt from the provisions of the California Environmental Quality Act (CEQA) and County CEQA Guidelines pursuant to CEQA Guidelines sections 15061(b)(3), 15061(b)(2), 15301 (Class 1), and 15308 (Class 8). Staff recommends that your Commission find the project exempt from CEQA and the County CEQA Guidelines. A Notice of Exemption was prepared for the project (Exhibit C).

OUTREACH AND ENGAGEMENT

A. County Department Comments and Recommendations

The Fire Department, Department of Parks and Recreation, and Public Works reviewed the Ordinance and had no comments. Staff sent the Ordinance to the Department of Public Health for review and did not receive a response.

B. Project Outreach and Engagement

On May 5, 2021, staff emailed 905 stakeholders to announce that the Ordinance is available for review online and that a public hearing is scheduled for June 8, 2022. Pursuant to Chapter 22.244 (Ordinance Amendments) and Section 22.222.180 of the County Code, the notice of public hearing was published in 14 local newspapers, including the Spanish-language newspaper La Opinión. Ordinance materials were posted on the Department's website and promoted through social media. Furthermore, the Department provided language access support in Spanish and Chinese, prepared translated project summary sheets (Exhibit G), and encouraged email or voicemail comments in multiple languages.

Of the numerous directives in the three motions adopted by the Board on September 15, 2021, this Ordinance implements one aspect of one motion. There are future opportunities for community engagement as County agencies work to implement all three Board motions. As directed by the September 15, 2021 Board motions, several County agencies will collaborate to build and ensure a robust, meaningful, and inclusive community engagement program that prioritizes frontline communities during the phase out, remediation, and visioning of future land uses.

C. Public Comments

No comments were received on the Ordinance at the time of this report.

Related to the Ordinance, staff received 521 form letters from persons living near the Inglewood Oil Field. These letters were in support of “a quick and just end to all drilling throughout LA County within five years” and "making oil and gas drilling a nonconforming use; expediting the phase-out period county-wide, including in the Inglewood Oil Field; and implementing a just transition to help workers." The form letters are attached to this report (Exhibit H).

Report Reviewed By: A. Bruce Durbin

A. Bruce Durbin, Supervising Regional Planner

Report Approved By:

Connie Chung, Deputy Director

LIST OF ATTACHED EXHIBITS	
EXHIBIT A	Title 22 Ordinance
EXHIBIT B	Board Resolution
EXHIBIT C	Notice of Exemption
EXHIBIT D	Amendment to Title 12
EXHIBIT E	Summary of Work: March 29, 2016 Board Motion
EXHIBIT F	Summary of Regulatory Agencies
EXHIBIT G	Project Summaries (English, Spanish, and Chinese)
EXHIBIT H	Public Comments

LOS ANGELES COUNTY REGIONAL PLANNING COMMISSION

MINUTES

Meeting Place: Virtual (Online) and by Teleconference

Meeting Date: June 8, 2022 - Wednesday Time: 9:06 a.m.

Present: Commissioners Duarte-White, Louie, O'Connor, Moon, Hastings

Ex Officio Members:

Director of Public Works: Ms. Aracely Lasso, Senior Civil Engineer

County Counsel: Ms. Elaine Lemke, Assistant County Counsel

Planning Director: Ms. Connie Chung, Deputy Director Advance Planning

Forester and Fire Warden: Mr. Juan Padilla, Supervising Fire Prevention Engineer

APPROVAL OF AGENDA

1. Motion/seconded by Commissioners Moon/Hastings – That the agenda for June 8, 2022 be approved.

At the direction of the Chair, the agenda was approved unanimously.

COUNTY COUNSEL REPORT

2. County Counsel stated for the record that while this is an online meeting, it is a public meeting the same as if it were held in person in the Commission's hearing room and rules that allow for an orderly meeting shall apply. As such, when speaking on an agendized item, comments should address the item on the agenda and no other issues.

Similarly, if speaking during public comment, comments should be limited to issues related to the business of the Regional Planning Commission.

COUNTY COUNSEL REPORT (Cont.)

If speakers do not remain on topic, they may be reminded by the Chair or myself to do so. Failure to discuss issues not related to the agendized item, may result in the loss of the right to speak on the item or other items, if directed by the Chair. In addition, speakers should refrain from conduct that is disruptive of the meeting. Doing so also could result in the loss of the right to speak on the agenda item or any other items.

Disruptive conduct can include, but is not limited to, threats made against other speakers, the Commission or its members, or any others participating in the meeting, profane comments not related to the agenda item, or disorderly or contemptuous behavior leading to a disruption of the orderly progression and holding of the meeting.

In such cases, the Chair will advise that the behavior is disruptive and direct that the speaker's microphone be disabled. That person may, however, continue to observe the meeting. Further, disruptive behavior communicated to the panelists of the meeting, which include the Commission and County staff, may result in the removal of that person from the meeting by disconnecting them from the online connection.

DIRECTOR/DEPUTY DIRECTOR

3. There were no reports given by the Chief Deputy Director.

Coastal

3(a) Project No. PRJ2022-000311-(3). Administrative Coastal Development Permit No. RPPL2022000757. Planner: Shawn Skeries. Applicant: Allyson Kane. 26315 Lockwood Road. Santa Monica Mountains Planning Area. Authorizing eighteen (18) roof-mounted Q-Cell solar modules and appurtenant equipment, including junction boxes and associated wiring, affixed to an existing single-family residence in the R-C-10,000 (Rural Coastal-10,000 square-feet minimum required lot area) Zone pursuant to Los Angeles County Code Section 22.44.940. This project is categorically exempt, Class 3 – New Construction or Conversion of Small Structures, pursuant to CEQA reporting requirements.

There being no presentation, the Commission received and accepted the information for Project No. PRJ2022-000311-(3).

MINUTES FOR APPROVAL

4. Motion/seconded by Commissioners Moon/Hastings – That the minutes for January 12, 2022 be approved.

At the direction of the Chair, the minutes were approved unanimously.

Motion/seconded by Commissioners Hastings/O'Connor – That the minutes for January 19, 2022 be approved.

At the direction of the Chair, the minutes were approved unanimously.

Motion/seconded by Commissioners Moon/Hastings – That the minutes for January 26, 2022 be approved.

MINUTES FOR APPROVAL (Cont.)

At the direction of the Chair, the minutes were approved unanimously.

Motion/seconded by Commissioners O'Connor/Moon – That the minutes for February 9, 2022 be approved.

At the direction of the Chair, the minutes were approved unanimously.

Motion/seconded by Commissioners Moon/Hastings – That the minutes for March 16, 2022 be approved.

At the direction of the Chair, the minutes were approved unanimously.

Motion/seconded by Commissioners Moon/Hastings – That the minutes for May 18, 2022 be approved.

At the direction of the Chair, the minutes were approved unanimously.

ADMISSION PROCEDURES

Staff announced if you are joining us via telephone and want to provide comment on any of the agenda items, please send an email to comment@planning.lacounty.gov and provide the agenda item number, your first name, your last name, your email address, your phone number, and indicate if you are the applicant or not the applicant

All participants' microphones will be muted during the meeting unless you have signed up to provide comment. If you have signed up to provide comment, your microphone will be unmuted when it is time for you to speak, and staff will call your name.

PUBLIC HEARING

Ordinance Studies

Project Approved

5. Project No. PRJ2020-000246-(1-5). Planner: Adrienne Ng. Advance Planning Case No. RPPL2020000624. Oil Well Ordinance. Countywide. An amendment to Title 22 (Planning and Zoning) of the Los Angeles County Code, for the unincorporated areas of Los Angeles County, to prohibit new oil wells and production facilities in all zones, designate existing oil wells and production facilities as nonconforming uses in all zones, and establish consistent regulations for existing oil wells and production facilities. This project is exempt pursuant to CEQA Guidelines sections 15061(b)(3), 15061(b)(2), 15301 (Class 1), and 15308 (Class 8).

Staff presented the Oil Well Ordinance, a project that amends Title 22 of the Los Angeles County Code to prohibit new oil wells and production facilities, designates existing oil wells and production facilities as nonconforming due to use, and establishes consistent regulations for existing oil wells and production facilities during the amortization period. The Ordinance applies to the unincorporated areas of Los Angeles County, except for the Baldwin Hills Community

PUBLIC HEARING (Cont.)

Standards District, areas designated as a specific plan, and uses operating under a valid discretionary permit.

On September 15, 2021, the County of Los Angeles Board of Supervisors (Board) approved a motion titled "Protecting Communities Near Oil and Gas Drilling Operations in Los Angeles County." The motion directed the Department of Regional Planning to "prohibit all new oil and gas extraction wells in all zones, including those allowed or planned for under existing discretionary permits, and designates all existing oil and gas extraction activities, including those allowed or planned for under existing discretionary permits, as legal nonconforming uses in all zones." The Ordinance implements the Board's vision to prioritize and protect the public health, safety, and welfare of residents living near oil wells and begins the process of a just transition away from fossil fuels and decarbonization of the economy.

On September 15, 2022, the Board also approved two related motions titled "Developing an Oil Well Cleanup Pilot Program for Los Angeles County" and "Developing a Comprehensive Strategy for a Just Transition Away from Fossil Fuels for Los Angeles County." The three motions assigned several County departments, including the Office of Oil and Gas at Public Works, Department of Public Health, Fire Department, and the Chief Sustainability Office to work on these directives.

The Ordinance has three major elements and key components; it prohibits new oil wells and production facilities. It designates existing oil wells and production facilities as nonconforming. Also, it establishes regulations for existing uses during the amortization period.

The Ordinance specifies a schedule for the effective date for regulations. Regulations for site maintenance, well plugging and abandonment, and restoration become effective on the date the Ordinance becomes effective. Regulations for well and site signage and the comment and complaint log become effective one year after the Ordinance goes into effect. Regulations for bonds become effective two years after the Ordinance goes into effect.

The Ordinance is consistent with and supportive of the goals, policies, and principles of the General Plan. The Department and Title 22 are responsible for land use and zoning regulations in the unincorporated areas of Los Angeles County. In addition, there are numerous federal, state, regional, and local agencies that regulate oil wells and production facilities in California and in Los Angeles County.

For further action and discussion visit:
http://lacdrp.granicus.com/ViewPublisher.php?view_id=1

Motion/seconded by Commissioners Louie/Moon – That the Regional Planning Commission close the public hearing and find that the exemptions qualify pursuant to state and local CEQA guidelines.

At the direction of the Chair, the item passed with Commissioners Louie, Moon, Duarte-White, and O'Connor in favor and Commissioner Hasting being recorded as no.

Motion/seconded by Commissioners Louie/Moon – That the Regional Planning Commission adopt the resolution recommending approval to the County of Los Angeles Board of Supervisors of the Oil Well Ordinance, Plan No. RPPL2020000624.

PUBLIC HEARING (Cont.)

At the direction of the Chair, the item passed with Commissioners Louie, Moon, Duarte-White, and O'Connor in favor and Commissioner Hasting being recorded as no.

PUBLIC COMMENT

6. Public comment pursuant to Section 54954.3 of the Government Code.

There were no requests by members of the public to address the Commission.

CONTINUATION OF REPORTS

7. Possible Call for Review of Decisions by Hearing Officer, pursuant to Section 22.240.010.B of the Los Angeles County Code.

There were no items Called up for Review by the Commission.

8. Commission/Counsel/Director Reports

There were no reports given by Commission/Counsel/Director.

ADJOURNMENT

A recording of the testimony received and the discussions held at this meeting and a copy of all findings and resolutions acted upon by the Commission are on file in the Department of Regional Planning.

The Commission adjourned at 10:38 a.m. to Wednesday, June 15, 2022.

Elida Luna

Elida Luna, Acting Commission Secretary

ATTEST

Yolanda Duarte-White, Chair

APPROVE

Connie Chung, Deputy Director
Advance Planning Division

Idle Well Program Report

On Idle and Long-Term Idle Wells in California

Reporting Period: January 1, 2018 to December 31, 2018
Prepared Pursuant to Assembly Bill 2729 (Ch. 272, Stats. of 2016)
July 1, 2019

About DOGGR

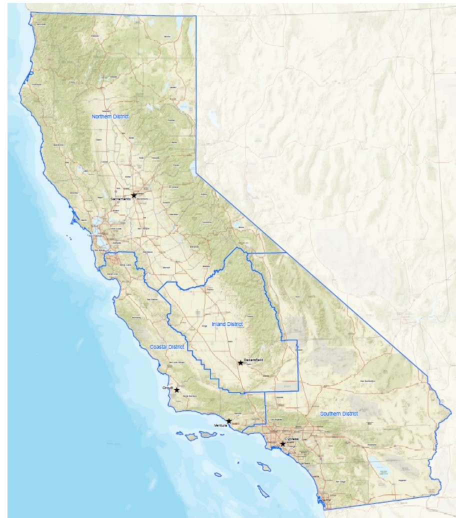
The Division of Oil, Gas, and Geothermal Resources (DOGGR) prioritizes the protection of public health, safety, and the environment in its oversight of the oil, natural gas, and geothermal operations in California. To do that, DOGGR uses science and sound engineering practices to regulate the drilling, operation, and permanent closure of energy resource wells. DOGGR also regulates certain pipelines and facilities associated with production and injection. These duties include witnessing tests, inspections, and operations that DOGGR is both authorized and required to perform.

When DOGGR was established in 1915, the initial focus of regulation was the protection of oil and gas resources in the State from production practices that could harm the ultimate level of hydrocarbon recovery. Early DOGGR regulations included well spacing requirements and authority to limit production rates. However, those regulations and the focus of DOGGR evolved and came to include the protection of public health, safety, and the environment.

DOGGR has grown significantly since it was established in 1915 and has taken major steps to ensure it will be able to handle challenges in a manner consistent with public expectations for a modern, efficient, collaborative, and science-driven regulatory agency.

DOGGR Districts

DOGGR operates out of four districts to best serve the needs of the State: Northern, Coastal, Inland, and Southern. Each district has its own offices where staff are available to assist the public and stakeholders with any requests. For more information about DOGGR, visit DOGGR's website.



DOGGR Districts (Click on image for larger view.)

Executive Summary

The Department of Conservation (DOC) submits this report to satisfy the legislative report requirements of Assembly Bill 2729 (AB 2729) (Williams, Ch. 272, Statutes of 2016) regarding the status of idle and long-term idle wells (LTIW) for the 2018 calendar year. This report spans the period between January 1, 2018 and December 31, 2018.

Oil and gas wells that are not operated and maintained on a regular basis present several hazards to the environment as well as public health and safety. Deteriorating wells can create a conduit for contaminants such as hydrocarbons, lead, salt and sulfates to enter freshwater aquifers and pose potential risks to surface water, air quality, soils and vegetation.

Idle wells also present a liability risk to California. Operators with a large inventory of idle wells may be postponing the cost to permanently plug and abandon the wells for financial reasons. If the operator becomes insolvent, the State may inherit liability to plug those idle wells.

Because of the risk and potential liability posed by idle wells in the State, DOC sponsored AB 2729 to discourage operators from leaving their wells in an idle state. Specifically, AB 2729 established new definitions for “idle well” and “long-term idle well,” updated fees assessed on idle wells, revised parameters for plans for the management and elimination of long-term idle wells (LTIW), and mandated the review, evaluation, and update of DOGGR idle well regulations. The reporting period addressed in this report reflects DOGGR’s first year implementing these revised statutory requirements. DOGGR invested significant resources in 2017 and 2018 to prepare for implementation, including processes to identify idle wells under the new definition, calculate and invoice new fee requirements, track fee payments, facilitate Idle Well Management Plan (IWMP) requirements, approve submitted IWMPs, and monitor IWMPs for compliance and annual reviews.

In 2018, DOGGR collected $4.3 million in idle well fees for all wells that met the definition of idle well in the preceding calendar year. DOGGR also oversaw the implementation of 76 IWMPs, resulting in the elimination of 988 LTIW. These numbers represent a substantial increase in revenue available to remediate hazardous well conditions to protect public health and the environment, and a dramatic increase in the rate of plugging LTIWs. Additionally, DOGGR updated its regulations for the management and testing of idle wells. These idle well regulations provide for the most rigorous testing standards for idle wells in the country to prevent damage to life, health, property, and natural resources. DOGGR anticipates that the new rules will further accelerate plugging of idle wells and LTIW.

The following key facts are included in this report:

- 29,292 wells met the definition of idle well and 17,576 of those met the definition of long-term idle well at some point during the reporting period.
- During the reporting period, the status of 1,346 idle wells changed from idle to plugged.
- During the reporting period, the status of 107 idle wells changed from idle to active.
- 76 operators submitted IWMPs for DOGGR approval.
    - 52 operators were found to be in compliance with the terms of their approved IWMPs at the conclusion of DOGGR’s annual review.
    - 16 operators voluntarily voided their 2018 IWMP and filed idle well fees, totaling $461,550 to remain in compliance with Public Resources Code section 3206.
    - Eight operators had their IWMP canceled by DOGGR due to failure to comply with the terms of their approved IWMPs. Two of the operators paid the idle well fees owed, and DOGGR is pursuing enforcement action against the remaining six operators. Four other operators received a Notice of Cancellation from DOGGR and appealed the cancellations, but in each of those cases the issues were resolved. Those four operators are included in the 52 operators found to be in compliance.

- Based upon the terms of the approved IWMPS, operators were expected to eliminate a minimum of 596 LTIW across the State.
    - Operators eliminated 988 LTIW, significantly exceeding expectations.
    - 9 operators eliminated more long-term idle wells than was required by their approved IWMP, resulting in those operators earning 453 elimination credits, which can be used for IWMP compliance for up to two years.
- DOGGR issued orders to plug wells to 14 operators in response to failure to file idle well fees in 2018.
- The final draft of the Requirements for Idle Well Testing and Management regulations were submitted to the Office of Administrative Law on December 21, 2018 and took effect on April 1, 2019.

In sum, this report demonstrates that DOGGR has made significant progress to identify idle wells, increase funds to address wells that have not been appropriately plugged, and work with operators to reduce the overall inventory of idle wells.

This report is divided into two parts: Part 1 summarizes the objective and scope of this report and Part 2 fulfills the legislative reporting requirements prescribed in Public Resources Code section 3206.3. The appendices provide the most current lists of idle wells, references and sources of the data, and a glossary of terms.

Introduction

Objective and Scope of Report

This report provides a comprehensive accounting of the idle well population to the California Legislature and the public. This report covers the idle well counts, orphan well counts, and IWMP statistics in California from January 1, 2018 through December 31, 2018.

A primary concern with idle wells is that they pose a risk to underground sources of drinking water and are possible sources of hydrocarbon emissions. Deteriorating wells can become conduits for contamination because many go through a fresh water resource. Poorly maintained idle wells can be sources of methane and hydrogen sulfide leaks. Additionally, a large inventory of idle wells pose an increased risk that wells will become deserted when operators become financially insolvent, potentially leaving the State to fund environmental remediation.

To address these problems, DOC sponsored AB 2729 to increase bonding requirements, require operators to maintain bonds for the life of the well, increase idle well fees, reauthorize the use of idle well management plans, and direct DOGGR to promulgate regulations to better protect public health, safety, natural resources, and the environment from risks associated with idle wells.

This report presents idle well information drawn from operator records submitted to DOGGR. These records include monthly volumetric reporting, IWMPs, and well histories required for permits to abandon wells.

Public Resources Code section 3206.3(a)(1) requires that this report address the following:

1. A list of all idle and long-term idle wells in the State by American Petroleum Institute identification number, operator, field, and pool.
2. A list of all wells whose idle or long-term idle status changed in the preceding year by American Petroleum Institute identification number with the disposition and current status of each well.
3. A list of orphan wells remaining, the estimated costs to abandon those orphan wells, and a timeline for future orphan well abandonment with a specific schedule of goals. Idle and LTIW that have become orphan wells shall be identified in the list. For the purposes of this report, an orphan well is a well that has no party responsible for it, leaving the State to plug it.
4. A list of all operators with plans filed with the Supervisor for the management and elimination of all long-term idle wells and the status of those plans.
5. Any additional relevant information as determined by the Supervisor.

Contact Information

For more information about the Idle Well Program, visit the Idle Well program webpage.

For questions regarding the content of this report, contact DOC's Public Affairs Office.

Acronyms and Abbreviations

DOGGR: Division of Oil, Gas, and Geothermal Resources

IWMP: Idle Well Management Plan

LTIW: Long-term idle wells

NTO: Notice to Operators

PY: Personnel Year

WellSTAR: Well Statewide Tracking and Reporting

Idle and Long-Term Idle Wells in California

1. Idle and Long-Term Idle Wells

Public Resources Code section 3206.3(a)(1)(A): A list of all idle and long-term idle wells in the state by American Petroleum Institute identification number and indicating the operator, field, and pool.

Public Resources Code section 3206.3(a)(1)(B): A list of all wells whose idle or long-term idle status changed in the preceding year by American Petroleum Institute identification number with the disposition and current status of each well.

See Appendix A-1 for the list of all wells that met the definition of idle well at any point in the 2018 calendar year.

See Appendix A-2 for the list of all wells that had a status change from idle to long-term idle in the 2018 calendar year.

See Appendix A-3 for the list of all wells that had a status change from idle well to plugged.

See Appendix A-4 for the list of wells that had a status change from idle well to active.

1.1 Idle and Long-Term Idle Wells in the State

In alignment with the 2017 Renewal Plan (for more information: Renewal Plan), DOGGR remains committed to improving its data management via deployment of the WellSTAR application. As of March 1, 2018, DOGGR implemented the WellSTAR release associated with reporting of monthly produced and injected volumes of oil, gas, and water as required in accordance with California Code of Regulations Title 14 section 1937.1 (d) and (e). This release changed the process for how operators report the monthly volumes to DOGGR. The reporting of monthly volumes is critical to the identification of idle wells and wells that return to active status. DOGGR utilizes the monthly reported volumes for each well in the State to evaluate which wells meet the definition of idle well and which wells qualify to have their status changed from idle to active.

The 2017 idle well inventory contains all wells that met the new definition of idle well and long-term idle well at any point in the 2017 calendar year. This inventory was updated by DOGGR when an operator self-reported a well changing status and DOGGR was able to verify the change and when an idle well was plugged and abandoned in accordance with Public Resources Code section 3208.

At the end of this reporting period, a known 29,292 wells met the definition of idle well at some point during the 2018 calendar year. Based on DOGGR's idle well inventory records, DOGGR estimates that an additional 1,200-2,400 wells became idle in 2018 which are unaccounted for in the 2018 inventory. Of the total idle well population, 17,576 idle wells had been idle for eight or more years at any point during the 2018 calendar year and thus meet the new statutory definition of long-term idle well.

1.2 Idle and Long-Term Idle Wells That Changed Since 2018

As of January 1, 2018, an estimated 29,324 wells were classified as idle wells and 17,595 of these idle wells were classified as LTIW. As of December 31, 2018, an estimated 28,032 wells were classified as idle wells and 17,870 of these idle wells were classified as LTIW. A total of 1,287 idle wells changed status to LTIW during the calendar year.

During the 2018 reporting period a total of 1,453 wells no longer met the definition of idle well. A total of 1,346 idle wells changed status from idle to plugged as they were plugged in accordance with Public Resources Code section 3208. A total of 107 idle wells are known to have changed status from idle to active. These wells returned to active status as a result of maintaining production of oil or natural gas, maintaining production of water used in production stimulation, or being used for enhanced oil recovery, reservoir pressure management, or injection for six continuous months within the year (Public Resources Code section 3008(d)). Due to the issues generating the idle well inventory described in section 1.1, DOGGR does not yet have an accurate accounting of all idle wells that changed status from idle to active during this reporting period.

2. Orphan Wells

Public Resources Code section 3206.3(a)(1)(C): A list of orphan wells remaining, the estimated costs of abandoning those orphan wells, and a timeline for future orphan well abandonment with a specific schedule of goals. Idle and long-term idle wells that have become orphan wells shall be identified in the list. For the purposes of this report, an orphan well is a well that has no party responsible for it, leaving the state to plug and abandon it.

See Appendix A-5 for the list of idle wells determined to be deserted.

2.1 Orphan Well Process

For purposes of this report, an orphan well has been defined as "a well that has no party responsible for it, leaving the State to plug and abandon it" (Public Resources Code section 3206.3(a)(1)(C)). DOGGR's determination that a well is orphan is a multi-step process that requires DOGGR to determine whether the well has been deserted by the operator, and then to determine whether there is a solvent entity responsible to plug the well. Therefore, the number of orphan wells identified in this report only reflects those orphan wells for which DOGGR has gathered sufficient information to issue a finding of desertion, and for which DOGGR has completed a financial solvency test.

Before issuing an order to plug a well, DOGGR must gather sufficient evidence to demonstrate the well has been deserted. If the operator fails to respond to the plugging order, then DOGGR will conduct a financial solvency test to decide whether to commit resources to enforcing the order or simply declare the well orphan. The financial solvency test is a factual inquiry into the solvency of the current operator and any other party responsible for plugging the well under Public Resources Code section 3237. If DOGGR determines the current operator does not have the financial resources to fully cover the cost to plug the well, previous operators that made a valid transfer after January 1, 1996, may be held responsible for the cost to plug the well (Public Resources Code section 3206.3(c)(1) & (2)). The statute does not allow DOGGR to hold a mineral interest owner responsible to plug the well unless the mineral interest owner retained a right to control the well operations that exceeds the scope of an interest customarily reserved in the lease (Public Resources Code section 3237(c)(3)). If, after researching the financial solvency for all potentially responsible parties, DOGGR determines there is no party with the financial resources to fully cover the cost to plug the well, the well can be declared orphan (Public Resources Code sections 3237(c)(1), 3251(b) & (e), 3206.3(a)(1)(C)).

DOGGR is continuing to gather evidence of desertion and conduct financial solvency tests for wells that are likely orphaned. The statutory changes implemented under AB 2729 have provided DOGGR the ability to more easily identify the wells that are likely orphan. Failure to comply with the new idle well requirements is conclusive evidence of desertion of the well. DOGGR's comprehensive efforts to implement and enforce these new requirements are facilitating systematic identification of each deserted well for which there is no solvent responsible party (Public Resources Code section 3206(c)).

The orphan well process can include multiple wells associated with the same operator and takes approximately 4-6 months to complete per order. Completion of the orphan process may result in the determination that the well is orphaned or identification of a solvent responsible party.

2.2 Orphan Well Inventory

DOGGR's Idle Well Program and Enforcement Unit are actively working the orphan well process to identify idle wells that have been deserted and for which there is no solvent responsible party, and can be considered orphan. During the 2018 reporting period, DOGGR issued orders to plug wells to 14 operators for a total of 55 idle wells. Eight operators failed to respond to the plugging orders resulting in the identification of 35 deserted wells.

The solvent entity research on the 35 deserted wells was still ongoing at the end of this reporting period with no wells being declared orphan on or before December 31, 2018. DOGGR estimates there are approximately 2,500 idle wells belonging to 943 operators that may be deserted and require orders to plug wells to initiate the orphan well process. An analysis of prior transfers and financial responsibility will require sustained effort.

2.3 Cost of Abandonment

Plugging costs on deserted wells are highly variable and, in many cases, difficult to predict. When an operator plugs one of their own wells, they are generally aware of the situation at a well including problems with obstructions that they may encounter based on having worked with the well. When DOGGR approaches a hazardous deserted well that could be as old as 100 years, it may not know if the previous operator had attempted to plug it in the past, what material may have been emplaced in the well, if the casing is intact, and other information that is critical to understanding potential cost drivers in a plugging job. Costs can range from as low as $11/foot in a well in Kern County if the project goes smoothly to well over $200/foot in an urbanized area with high ancillary costs, such as temporarily moving utility lines, higher staging and mobilization costs, and where “junk” obstructs downhole operations and leads to delays and cost overruns.

More detailed estimates will be provided in the next reporting period as DOGGR will have completed the orphan well process for the deserted wells identified in the section 2.2 and awarded contracts to plug and abandon those wells declared orphan.

2.4 Timeline of Future Orphan Well Abandonment

DOGGR is appropriated funds annually to plug wells that have been declared orphan. Senate Bill 724 (SB 724) (Lara, Chapter 652, Statutes of 2017) temporarily increased the annual appropriation for orphan well abandonment from $1 million to $3 million per fiscal year commencing on July 1, 2018 (Public Resources Code section 3258(a)(1)). This appropriation will revert to $1 million per fiscal year commencing with the 2022-2023 fiscal year. DOGGR intends to utilize the full amount of these funds annually to plug orphan wells.

Based on the cost range provided above, it is estimated that 23 to 100 wells may be plugged and abandoned for fiscal years 2018-2019 through 2021-2022. For fiscal year 2022-2023 and beyond, an estimated 7 to 33 wells may be plugged and abandoned annually. These annual benchmarks will fluctuate depending on the cost to plug each orphan well. Many of the costs to plug wells are driven by conditions downhole that remain unknown until projects commence work. The prioritization of orphan wells to be plugged each year will be based upon the prioritization factors for idle wells described in California Code of Regulations Title 14 section 1772.4, which includes economic efficiencies associated with grouping wells by location.

DOGGR utilized the 2018 reporting period to develop and implement a more standardized orphan well process, including new methods to identify wells that may be orphan. The 35 wells that commenced the orphan well process in 2018 will complete the process in 2019. The wells from this grouping that have been determined to be orphan will be plugged and abandoned using the appropriated funds for the 2018-2019 fiscal year.

DOGGR is working to streamline both the orphan well determination and contracting processes. This year will also be used to identify orphan wells to plug in Fiscal Year 2019-2020 and build a queue of orphan wells for subsequent fiscal years.

The identification of wells requiring the orphan well process will be an ongoing effort. The two most common means by which these wells may be identified are: 1) failure to file annual idle well fees; and, 2) identification at the DOGGR district level based on finding of desertion under Public Resources Code section 3237.

3. Plans for the Management and Elimination of Long-Term Idle Wells

Public Resources Code section 3206.3(a)(1)(D): A list of all operators with plans filed with the supervisor for the management and elimination of all long-term idle wells and the status of those plans.

See Appendix A-6 for the list of operators with 2018 IWMPs and their status.

3.1 Idle Well Management Plans

Under Public Resources Code section 3206(a)(2), operators may, in lieu of paying annual idle well fees, file an IWMP that provides for the management and elimination of all the operator's LTIW. An operator may eliminate a LTIW by either properly plugging and abandoning the well in accordance with the requirements of Public Resources Code section 3208 or demonstrating to DOGGR's satisfaction that the well has maintained production of oil or gas or been used for injection for a continuous six-month period.

Under the requirements of AB 2729, IWMPs must commit operators to eliminating a minimum percentage of their LTIW each calendar year. The required rate of elimination of LTIW is based on the total number of statewide idle wells in the operator's possession on January 1 of each year. Unless and until the operator has no LTIW, the operator must eliminate the required rate of wells annually. The required elimination rates are as follows:

- Operators with 250 or fewer idle wells must eliminate at least 4% of their LTIW.

- Operators with 251 to 1,250 idle wells must eliminate at least 5% of their LTIW.
- Operators with more than 1,205 idle wells must eliminate at least 6% of their LTIW.

Public Resources Code section 3206(a)(2)(B)(iii) affords operators the opportunity to receive credits for eliminating greater than the minimum required number of LTIW. These credits may be applied to future minimum elimination requirements in the operator's IWMP but expire after two years.

In this reporting period, DOGGR received and approved IWMPs from 76 oil and gas operators. Based upon the terms of the approved IWMPS, operators were expected to eliminate a minimum of 596 LTIW. Operators significantly exceeded the expected number of eliminations and eliminated 988 LTIW. 19 operators eliminated more LTIW than was required by their approved IWMP, resulting in those operators earning 453 elimination credits, which can be used for IWMP compliance for up to two years. On January 1, 2019, the Supervisor conducted an annual review of each 2018 IWMP which yielded the following results:

- 52 operators were found to be in compliance with the terms of their approved IWMPs.
- 988 LTIW were eliminated in 2018 as part of approved IWMPs.
- Four operators eliminated all their LTIW in the State. Two of these operators plugged all their idle wells in the State.
- 16 operators voluntarily voided their 2018 IWMP and filed idle well fees, totaling $461,550 to remain in compliance with Public Resources Code section 3206.
- Eight operators had their IWMP canceled by DOGGR due to failure to comply with the terms of their approved IWMPs. Two of the operators paid the idle well fees owed, and DOGGR is pursuing enforcement action against the remaining six operators. Four other operators received a Notice of Cancellation from DOGGR and appealed the cancellations, but in each of those cases the issues were resolved. Those four operators are included in the 52 operators found to be in compliance.

3.2 Non-Compliant Idle Well Management Plans

If an operator fails to comply with their approved IWMP, then the IWMP for that operator is revoked and the operator is not eligible to propose a new IWMP for any of its idle wells for the next five years. An operator may appeal to DOC's Director regarding the Supervisor's determination of non-compliance. If the Supervisor's determination that the operator failed to comply with the IWMP is not timely appealed, or if the Director upholds the Supervisor's determination upon appeal, then the operator is required to immediately file the idle well fees due for each year that the operator failed to comply with the IWMP.

Furthermore, failure to file the idle well fee due for any well is conclusive evidence of desertion, permitting the Supervisor to order the well abandoned pursuant to Public Resources Code section

3237.

DOGGR issued Notices of Cancellation to 12 operators for failing to comply with the requirements of the IWMPs submitted in 2018. One operator appealed the Notice of Cancellation and provided the required documentation to demonstrate compliance resulting in rescission of the Notice of Cancellation. Three operators appealed the Notice of Cancellation and settlement agreements were reached. Eight operators had their IWMPs revoked as they failed to appeal the cancellation of their plan and to pay the required idle well fees. Two operators had their IWMP revoked and filed the idle well fees required.

3.2.1 Notice of Cancellation – Rescinded

DOGGR rescinded one Notice of Cancellation after the operator provided the necessary documentation to demonstrate compliance. During this demonstration, DOGGR determined that the operator exceeded the minimum elimination requirement in its IWMP. This operator is eligible to propose an IWMP for the 2019 calendar year.

- E & B Natural Resources, Operator Code E0100

3.2.2 Notice of Cancellation - Settlement Agreements

DOGGR reached settlement agreements with all three operators that appealed the Notice of Cancellation.

- TEG Oil & Gas U.S.A., Inc., Operator Code T0135
- First Oil and Gas Company, Operator Code T0275
- HVI Cat Canyon, Operator Code G3515

3.2.3 Notice of Cancellation – IWMP Revoked

DOGGR revoked the IWMPs for eight operators that failed to appeal the cancellation of their plan. These operators will be prohibited from submitting an IWMP for five years, regardless of whether the operator pays the required fees in future years.

Two operators filed the idle well fees due in response to the Notice of Cancellation.

- White Knight Production LLC, Operator Code W2050
- Miocene Operating Services Inc, Operator Code M6655

Six operators have failed to pay the required idle well fees. DOGGR is pursuing enforcement action against these operators in 2019 and will provide the results in the 2020 Annual Report on Idle and Long-Term Idle Wells in California.

- Caltico Oil Corp., Operator Code C1380
- H2O-CH4, LLC, Operator Code H0070
- Citadel Exploration Inc, Operator Code C5845
- R. J. Bellevue, Inc, Operator Code B3079
- Valid Energy Company, Operator Code V0175
- Jaco Production Company, Operator Code J0700

4. DOGGR Enforcement

DOGGR's Idle Well Program and Enforcement Unit work closely together to pursue enforcement actions against operators that fail to comply with idle well statutory and regulatory requirements. During this reporting period, DOGGR's Idle Well program focused primarily on failure to file idle well fees and comply with IWMPs. Failure to file the annual idle well fee prescribed in Public Resources Code section 3206(a) is conclusive evidence of desertion. This permits the Supervisor to order that the well be plugged pursuant to Public Resources Code section 3237.

Idle well fees are assessed annually for the preceding calendar year. During this reporting period, idle well fees were assessed based on the idle well inventory for the 2017 calendar year. In this effort, DOGGR collected $4,311,200 in idle well fees in 2018. DOGGR identified 957 operators that failed to file idle well fees for 2,555 idle wells in 2018. Within the reporting period, 14 of these operators were issued orders to plug 55 wells. There is also a backlog of pending orders for 943 operators to plug a total of 2,500 idle wells.

These enforcement efforts support the orphan well process as described in section 2.1 of this report. Future enforcement efforts will expand the focus to comply with new idle well regulations in addition to statutory requirements.

Appendix A - Idle Well Lists

A-1 2018 Calendar Year Idle Well Inventory

List of all wells that met the definition of idle well at any point in the 2018 reporting period. The list includes the API number and designation of the well, well type, operator, field, pool, idle start date, and LTIW status identified for each well.

A-2 Idle Wells That Changed Status from Idle to Long-Term Idle Well

List of all idle wells that met the definition of LTIW for the first time in the 2018 reporting period. The list includes the API number and designation of the well, well type, operator, field, pool, and idle start date.

A-3 Idle Wells That Changed Status from Idle to Plugged

List of all idle wells that changed status to plugged in the 2018 reporting period. The list includes the API number and designation of the well, well type, operator, field, pool, and idle start date.

A-4 Idle Wells That Changed Status from Idle to Active

List of all idle wells that changed status to active in the 2018 reporting period. The list includes the API number and designation of the well, well type, operator, field, pool, and idle start date.

A-5 Idle Wells Determined to be Deserted

List of all idle wells that have been determined to be deserted. The list includes the API number and designation of the well, last known operator, field, and order number and date for each well. These wells commenced the orphan well process in 2018.

A-6 Operators with 2018 IWMPs & Current Status

List of all operators with IWMPs submitted in 2018 and the status of each IWMP as of the annual review, including the minimum number of LTIW required to be eliminated, the actual number of LTIW eliminated, and credits earned for LTIW eliminated in excess of the minimum requirement.

Appendix B - References and Data Sources

The following were used as references for this report:

- California Statutes and Regulations for Conservation of Oil, Gas, and Geothermal Resources (April 2019)
- Notice to Operators 2018-03: WellSTAR Release 2.0 – New and updated forms, e-permitting, and electronic reporting (March 7, 2018).
- Notice to Operators 2018-14: WellSTAR – New and updated forms, and electronic reporting (December 7, 2018).
- Notice to Operators 2019-01: WellSTAR – New and updated forms, and electronic reporting (January 15, 2019).
- Renewal Plan for Oil and Gas Regulation: Changing past practices to usher in a new era of oil and gas regulation (October 2015).

The following were used as data sources for this report:

- California Well Information Management System (CalWIMS) is an internal electronic database used to maintain, monitor, and track well information.
- IWMP documents submitted by operators.
- WellSTAR: Well Statewide Tracking and Reporting a new electronic database used to maintain, monitor, and track well information.
- WellSTAR: Internal database used to maintain, monitor, and track well information pertaining to monthly production and injection volumes. Decommissioned March 2018.

Appendix C - Glossary

AB 2729

AB 2729 (Williams, Ch. 272, Statutes of 2016) redefined an idle well and a long-term idle well; removed the option for a large operator to secure an escrow account or post a “super blanket bond” to avoid paying idle well fees; allowed an operator to implement an IWMP in lieu of paying idle well fees; and provided a means through which a person who acquires land with one or more wells on it to re-plug and abandon the well(s). It also required the Supervisor, on or before July 1, 2019, and annually thereafter until July 1, 2026, to submit to the Legislature a comprehensive report on the status of idle and LTIW for the preceding calendar year.

Idle Well

Public Resources Code section 3008, subdivision (d): “Idle well” means any well that for a period of 24 consecutive months has not either produced oil or natural gas, produced water to be used in production stimulation, or been used for enhanced oil recovery, reservoir pressure management, or injection. For the purpose of determining whether a well is an idle well, production or injection is subject to verification by the division. An idle well continues to be an idle well until it has been properly abandoned in accordance with Section 3208 or it has been shown to the division's satisfaction that, since the well became an idle well, the well has for a continuous six-month period either maintained production of oil or natural gas, maintained production of water used in production stimulation, or been used for enhanced oil recovery, reservoir pressure management, or injection. An idle well does not include an active observation well.

Idle Well Fees

Public Resources Code section 3206, subdivision (a)(1): No later than May 1 of each year, for each idle well that was an idle well at any time in the last calendar year, file with the Supervisor an annual fee equal to the sum of the following amounts: (A) One hundred fifty dollars ($150) for each idle well that has been an idle well for three years or longer, but less than eight years. (B) Three hundred dollars ($300) for each idle well that has been an idle well for eight years or longer, but less than 15 years. (C) Seven hundred fifty dollars ($750) for each idle well that has been an idle well for 15 years or longer, but less than 20 years. (D) One thousand five hundred dollars ($1,500) for each idle well that has been an idle well for 20 years or longer.

Idle Well Management Plan (IWMP)

Public Resources Code section 3206, subdivision (a)(2): File a plan with the Supervisor to provide for the management and elimination of all LTIW. (A) For the purposes of the plan required by this paragraph, elimination of an idle well shall be accomplished when the well has been properly abandoned in accordance with Section 3208, or it has been shown to the division's satisfaction that, since the well became an idle well, the well has maintained production of oil or gas or been used for injection for a continuous six-month period.

Long-Term Idle Well (LTIW)

Public Resources Code section 3008, subdivision (e): "Long-term idle well" means any well that has been an idle well for eight or more years.

Measured Depth

The length of the wellbore measured along the path of the well.

Plug and Abandon

Public Resources Code section 3208, subdivision (a): For the purposes of Sections 3206 and 3207, a well is properly abandoned when it has been shown, to the satisfaction of the Supervisor, that all proper steps have been taken to isolate all oil-bearing or gas-bearing strata encountered in the well, and to protect underground or surface water suitable for irrigation or farm or domestic purposes from the infiltration or addition of any detrimental substance and to prevent subsequent damage to life, health, property, and other resources. For purposes of this subdivision, proper steps include the plugging of the well, decommissioning the attendant production facilities of the well, or both, if determined necessary by the Supervisor.

SB 724

SB 724 (Lara, Ch. 652, Statutes of 2017) temporarily increased funding to plug and remediate deserted oil and gas wells and oil field facilities from $1 million to $3 million. It required the Division to establish criteria to prioritize deserted wells and facilities for remediation. This bill made several technical and conforming changes to the Public Resources Code related to time lines for permitting and idling of oil wells. This bill clarified existing law to specify that the Division, as a part of an order requiring the plugging and abandonment of a deserted well, may also require the operator to address the adjacent production equipment associated with the well and conduct site remediation if necessary.

IDLE WELL MENU

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Managing Environmental Liability: An Evaluation of Bonding Requirements for Oil and Gas Wells in the United States

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Supporting Information

ABSTRACT: Inactive oil and gas wells present an environmental hazard if not properly plugged. Upon drilling a well, operators are required to post a bond, which ensures that the operator has an incentive to plug and abandon (P&A) at the end of the well's life, and that, if the state is left with the liability of managing "orphaned" wells, it can cover the cost of P&A. Using data from 13 state agencies on their orphaned well plugging expenditures, we provide new estimates of P&A costs in the United States and compare them to bond amounts. Current state bonding requirements are insufficient to cover the average P&A cost of orphan wells in 11 of these 13 states. These should be reviewed and revised where necessary. We also examine the factors influencing P&A costs using detailed data on orphaned wells in Kansas. Given the variability of P&A costs, bonds would be more effective if they varied by factors that are meaningful in explaining P&A costs, such as well depth, location, and proximity to groundwater. State regulators can use the statistical approach developed in this paper to improve bonding requirements and to better predict the P&A costs of their orphaned wells.

INTRODUCTION

In the United States, after an oil or gas well has suspended production for a period of time, state regulations require it to be permanently "plugged and abandoned" (P&A), and the land surrounding the well site reclaimed to resemble its original condition. Wells that are not properly plugged can leak methane,[1−3] a potent greenhouse gas. Inactive oil and gas wells which have not been properly plugged may also provide a pathway for surface runoff, brine, or hydrocarbon fluids to contaminate surface water and groundwater.[4−7] This can render the water nonpotable, especially if the brine has elevated total dissolved solids or contains naturally occurring heavy metals or radioactive materials.[8] The upward migration of fluids may occur especially if, in the process of horizontal drilling, hydraulically generated fractures intersect existing inactive wells that have not been properly plugged.[9] Well sites that are not properly reclaimed can contribute to habitat fragmentation[10] and soil erosion,[11] and equipment left on-site can interfere with agricultural land use and wildlife habitat.[12] Therefore, once a well has reached the end of its life, the owner is required to properly P&A the well and reclaim the surrounding land. In the rest of this paper, we refer to the entire process of decommissioning as plugging or P&A, unless we are specifically discussing reclamation.

As of 2007, across 26 oil and gas-producing states, there were an estimated 149,370 orphaned wells, that is, wells which have not yet been plugged and abandoned, yet no longer have a solvent owner.[13] However, these are state-reported numbers and capture only known wells. Pennsylvania has an estimated 470 000−750 000 orphan wells, with locations unknown.[14] Recent work has highlighted the varied quality of wellbore drilling records, making it challenging to ascertain the location of orphaned wells.[15] While the majority of orphaned wells are legacy wells that were drilled before well-permitting and well-plugging regulations were established, many are also modern wells that have become orphaned in spite of these regulations. For instance, in Texas, 38% of the state's list of 5850 orphaned wells (as of June 2017) were still producing up until 10 years ago.[16] In addition, some states have seen increases in the number of wells being orphaned amid falling oil prices and the recent industry downturn.[17]

At the time a well is drilled, an operator is required to post a bond that is returned only after the well is plugged. Such assurance bonds are useful mechanisms for forcing producers to take into account the potential external costs of their decisions.[18] They create an incentive to minimize end-of-life cleanup costs throughout all stages of the well's life, and shift the burden of proof from the regulator to the firm.[19,20] Bonds also help ensure that there will be adequate financial resources to correct any environmental damage that may occur in future.[21] Finally, bonding guarantees that if an operator fails to P&A, the state will have the financial resources (at least up to the bond amount) to cover P&A costs. Outside of the oil and gas industry, bonds are or can be used to regulate forestry,[22] industrial activities,[23] surface mining,[24,25] and coastal development.[26] Here we focus on the

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end-of-life liabilities of oil and gas wells; however, bonding mechanisms could also cover other risks associated with oil and gas extraction, such as water pollution.[27]

Despite requiring bonding, many states have accumulated large inventories of orphaned wells. These inventories may grow as complaints of neglected wells are reported, legacy wells are located, or companies become defunct.[28] Because of funding constraints, only a portion of these orphaned wells can be plugged each year,[29] meaning that the public faces the risk of environmental damage from the remaining wells. Existing research suggests that bond revenues have been insufficient to finance plugging costs in certain states; for instance, bond revenues in Texas covered just 16% of the cost of plugging orphaned wells in fiscal year 2015.[30] In such cases, the remaining costs must be financed with other funding sources, such as a state treasury. The Wyoming Oil and Gas Conservation Commission's 2013 plugging plan, for instance, recommends the use of conservation tax revenues to supplement bond revenues to finance the plan.[31] Well plugging funds are often also financed by industry fees. Supporting Information (SI) Table S1 lists the sources of funding for plugging in a number of states.

Understanding the factors that cause wells to become orphaned, as well as the liability that state agencies face, requires an understanding of the costs of P&A and how these compare to well bonds. If P&A costs exceed the required bond, the effectiveness of the bond is diminished. Further, it is common industry practice for large operators to transfer ownership of their wells to smaller operators when production rates decline, and regulators typically allow a lease to be transferred as long as the buyer can cover the cost of the bond attached to it. A low bond amount ensures that even a small operator can easily meet bonding requirements; however, these operators are less likely to have the financial means to bear the true cost of P&A[32,33] and are also more likely to declare bankruptcy.

This study offers an in-depth analysis of the costs of plugging orphaned wells in 13 states and how they compare to the bond amounts in each state. We show that current bond amounts are lower than the average cost of plugging orphaned wells in all but two of the 13 states analyzed. Our study updates and extends prior work that has been done. While there are some estimates of P&A costs in the literature, these are anecdotal,[32,34] limited to one state,[35] or focused only on wells on federal land under the jurisdiction of the Bureau of Land Management.[36,37] The only systematic review of plugging costs across all oil-and-gas-producing states reports cost estimates from 12 years ago,[13] whereas we provide updated estimates for 13 states that have had extensive plugging activity. Our recommendation to review and increase state bond amounts also echoes similar recommendations that have been made in the literature.[32,34,36] However, to our knowledge, ours is the first study to base this recommendation on a systematic comparison of bond amounts to historic average plugging costs.

In addition to its usefulness for assessing the adequacy of bonding requirements, obtaining accurate cost estimates is also useful for researchers and regulators attempting to predict the cost to plug existing inventories of orphaned wells.[29,32,35,37−39] Average cost estimates in the existing literature vary considerably, ranging from $630 per well in Missouri[13] to $700,000 in Pennsylvania.[32] This suggests that it is important to determine the factors driving this variation and to use these when predicting P&A costs. Thus, in addition to comparing P&A costs against bond amounts, we also use more detailed data provided by the state of Kansas to examine how various factors affect P&A costs.

The only cost factor that has been explored in the peer-reviewed literature to date is well depth. Andersen and Coupal (2009) use data on the costs of plugging a sample of 225 wells in Wyoming to estimate an average cost of $10.50 per foot of well depth, which they use to calculate an estimated total cost of $3.15 billion to plug the known inactive wells in Wyoming.[35] Mitchell and Casman (2011) use Andersen and Coupal's estimate of per foot costs in Wyoming to estimate the average cost of plugging a well in Pennsylvania.[32] We confirm that well depth is an important factor affecting P&A costs; however, it is not the only factor. There is also large spatial heterogeneity in P&A costs, implying that it is difficult to generalize costs across jurisdictions. By analyzing several major factors affecting P&A cost, we offer a framework and method for more accurately estimating P&A costs for any given population of wells.

The cost of a project may be high especially when it includes extensive site reclamation activities. For instance, in Colorado, seven reclamation projects were completed between 2013 and 2015, with costs ranging from $7,225 to $143,928.[40] The most expensive project involved removing two well pads and two access roads. Even for projects that do not involve reclamation projects, there can still be significant variation in plugging costs, as our analysis reveals.

■ MATERIALS AND METHODS

Data. We approached state regulators for data on their expenditures to P&A orphaned wells. Using the statistics reported by the Interstate Oil and Gas Compact Commission (IOGCC),[13] we ranked states by the number of wells plugged and number of orphaned wells. We prioritized, for data collection, states that had plugged more wells, had a larger number of orphaned wells, and had higher levels of production. From each state, we requested:

(1) costs for each well plugged or each contract completed (a plugging contract may involve more than one well);
(2) characteristics of the wells plugged, including location, depth, and completion date (the date the well was originally drilled and completed); and
(3) sample project contracts with itemized costs.

In total, we obtained cost data of varying quality for 31 821 wells in 13 states that were plugged between 1978−2015. We obtained sample contracts with itemized costs from five states, allowing us to compare the costs of individual project components in these states. One challenge in our study is the inaccessibility of data on private sector plugging costs and our corresponding reliance on data from states on plugging orphaned wells. Because of this, the average P&A costs that we present may not be representative of the costs of plugging all types of wells, including those plugged by operators. We consider this issue in the Results and Discussion section.

Kansas was the state with the most comprehensive data available on costs and well characteristics for the largest number of observations (5838). Therefore, we used Kansas data to analyze how specific factors affect P&A costs. The data do not indicate whether the wells are horizontal or whether they were hydraulically fractured; however, we can assume that these wells are mostly vertical, conventional wells. We deduce this from the age of the wells; the 400 wells for which we have age information were all drilled before 2000. Before 2005, there were only 86 horizontal wells in Kansas,[41] and while the first hydraulic fracturing operation in Kansas was in 1947,[42] modern hydraulic fracturing (combining horizontal drilling with high-volume,

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Table 1. Average Costs of Plugging in 13 States, in Ascending Order[a]

state	sample size	mean cost (our data)	standard deviation	median	minimum	maximum	mean cost (IOGCC 2008)
Plugging and Reclamation							
IN	480	10,470	10,232	7,651	483	89,845	8,423
NY	120	10,619					13,222
AR	612	11,053					5,636
PA	3,068	14,553	31,617	8,377	2,839	435,000	9,065
OH	2013	18,386	11,084	12,711	2,300	72,317	11,306
MT	312	20,373	31,617	11,006	274	263,596	16,522
CO	64	29,903	31,244	16,304	1,360	145,431	14,337
MI	289	78,715	66,285	62,076	474	575,945	55,376
Plugging Only							
KS	5,840	5,021	4,562	3,733	105	107,910	2,847
IL	2,013	7,617	8,008	7,087	394	341,004	4,063
TX	16,503	10,908					1,900
OK	394	15,205	13,900	10,948	1,706	100,000	3,508
CA	113	30,877					15,389

[a]Note: Costs are adjusted to 2014$ using the Producer Price Index for the oil and gas extraction industry from the Bureau of Labor Statistics. Not all states report data on the costs of plugging individual wells: five states had data on costs per well (PA, MT, KS, IL, and OK), six had costs per contract (IN, NY, OH, CO, MI, and CA), with multiple wells plugged in each contract, and two had total costs incurred by the state and the number of wells plugged in each year (AR and TX). States in the top panel report costs that include both plugging and site reclamation costs; the five states in the bottom panel report on only the costs of plugging. We do not report detailed summary statistics for four states because we do not have data that are sufficiently granular. See SI Table S4 for descriptions of each data set.

slick-water hydraulic fracturing) became mainstream only over the last two decades. Cost components include the costs of using equipment such as the drilling rig, pulling unit, backhoe, and vacuum truck; material costs for plugs such as cement or cast-iron bridge plugs; special services such as perforation or casing cuts; fees for waste disposal; and labor or supervision costs. Some contracts also include the cost of assessing the site prior to P&A operations and the cost of equipment mobilization and demobilization. Reclamation costs were not included.

Background on Factors Influencing Costs. Proper P&A is essential for mitigating the risk of methane leakage and groundwater contamination from these wells, as it ensures that the hydrocarbon zone is permanently isolated from surface water, land, and freshwater aquifers (known as "zonal isolation"). In particular, legacy wells may not have been drilled with sufficient well casings or completed with cement of sufficient density to ensure zonal isolation. Even with modern well constructions, however, migratory pathways may develop if the wellhead fails,[43] if the casing corrodes or collapses,[7] or if the cement shrinks.[1] The effective permeability of unplugged wells—that is, the wells' potential to leak methane—has been found to be higher than that of plugged wells.[9] In Ohio, over a 25-year period from 1983 to 2007, 41 of 185 occurrences of groundwater contamination from wells were due to leakage from orphaned wells; in Texas, the equivalent figure was 30 of 211 occurrences.[6]

The cost of permanently decommissioning a well includes the cost of P&A and the cost of site reclamation. P&A involves plugging the wellbore with cement,[43] with states imposing different requirements on the extent of cementing and type of cement to be used. The wellhead is then removed and the surface casing is cut off, sometimes above the surface so the well can be easily marked, and sometimes below the depth of a plow (typically around three feet) to ensure that the well does not interfere with surface and agricultural operations. Reclamation occurs after P&A and typically involves removing surface equipment, emptying and reclaiming pits, hauling waste to an off-site disposal facility, and restoring the surface. Depending on the original condition of the well site and its designated land use (e.g., urban or rural), the terms of the lease agreement, and the degree of contamination, the site reclamation process may also involve the treatment of contaminated soil and groundwater, removal of roads and flowlines, recontouring, and revegetation.[44−47]

Therefore, P&A costs can vary by several factors. Per-well plugging costs are likely to be higher when: wells are deeper; the well casing or cement is in poor condition (also associated with the well being older); plugging regulations are more stringent; the well site is densely vegetated and more difficult to access; the well is closer to rivers, streams, or groundwater aquifers; oil and gas production is booming and competition for plugging service providers is high; or fewer wells are plugged in a contract.

Regression Analysis using Data from Kansas. To study the factors affecting plugging costs in Kansas, we use five data sets (see SI for details) that provide data on (1) 9423 orphaned wells, (2) detailed well characteristics, (3) well location information, (4) oil and gas prices, and (5) land classification data.

We specify our model of factors affecting plugging cost as follows:

$$\log(C_{i,t}) = f(\mathbf{X}_i, P_t, \delta_i, t; \theta) + \varepsilon_{i,t}$$

where $C_{i,t}$ is the P&A cost in 2014$ for individual well i in year t. $\mathbf{X}_i$ is a vector of attributes associated with well i (depth, age, type of well, e.g. oil or gas, completion year, surrounding-area land use, and number of wells plugged in each contract). P_t is the oil price in year t in 2014$. We include district indicator variables, δ_i, to capture time-invariant differences across districts (such as geology or topography). We include a year trend, t, which captures a linear trend in costs over time, such as improvements in plugging technology over time. θ is a vector of parameters to be estimated. ε_{it} is a random error term. We estimate the equation using ordinary least-squares.

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RESULTS AND DISCUSSION

Heterogeneity in Costs Across States. Summary statistics across 13 different states show heterogeneity in cost (Table 1). In 11 of the states, average plugging costs in our sample are larger than those reported by the IOGCC in 2008. The nine states for which we are able to calculate more detailed summary statistics (i.e., median, minimum, etc.) have a median cost below the average, a large standard deviation, and a large range of costs. The most expensive projects cost significantly more than the average. This suggests that within-state average costs are skewed upward by especially expensive projects.

P&A costs vary with factors such as well depth, age, and the rates charged by different service providers. For instance, the hourly use of a drilling rig can cost $85 in Kansas and $240 in Pennsylvania. Perforation (used to circulate cement around an uncemented casing) can cost $210/run in Kansas, $760/run in Ohio, and $900/run in Texas. Prices can be different even within a state, with one service provider in Kansas charging $75/hour for the use of a pulling rig, and another charging $173/hour.

Reclamation costs also vary. We obtained three sample site reclamation contracts from the Oklahoma Energy Resources Board, an industry-funded government agency that manages site reclamation projects in the state. The three contracts for reclamation cost $8,000, $17,000, and $58,000, revealing a wide range of project costs and activities. The least expensive reclamation project involved the removal of flowlines, gravel and concrete, topsoil, and debris, followed by sodding (recontouring of soil and replanting of sod over disturbed areas). The most expensive reclamation project included the construction of a pond and removal of a road.

Our data illustrate that there is great spatial heterogeneity in the variables affecting costs. Thus, it cannot be assumed that plugging costs in any one state are representative of costs in general; this assumption has been made elsewhere in the literature.[32] Costs should instead be estimated on a state-by-state basis. In the following section we focus in on Kansas to reveal how different factors drive the variation in plugging costs in that state.

Factors Affecting P&A Costs: Descriptive Statistics for Kansas. We use a data set on orphaned wells plugged in Kansas between 1996 and 2013. We exclude injection, salt water disposal, and water supply wells and end up with a subsample that contains only oil and gas wells—6,147 of the 9,423 wells in the original database of orphaned plugged wells. Of these, we retain only wells with information on well depth and plugging cost, yielding a total of 5838 observations (see SI Table S2 for summary statistics).

These 5838 wells cost the state a total of $29.3 million to plug. Plugging costs for individual wells range from $105 to $107,910, with an average of $5,020 and a median of $3,733. Average costs are skewed upward by the more expensive projects. SI Figure S1 shows this long-tailed distribution of costs. Well depths range from 10 feet to 6250 feet, with an average of 787 feet. Only 428 observations (7.3% of our data set) have information available for the year in which the well was drilled, thus we can only calculate well age for these observations. Missing information is typical across other jurisdictions as well.[18] The wells in this subset of 428 orphaned wells were drilled between 1916 and 1999, with a mean year of 1973. They range from 3 years to 85 years of age with a mean age of 32 years. We observe that well depth and well age both correlate with plugging cost (SI Figures B2 and B3), although the correlation coefficient on well depth is larger (0.58) than that on well age (0.15).

Kansas introduced more stringent well construction regulations in 1982 and so we include an indicator for whether the well was drilled after 1985, allowing for a three-year lag for the regulation to have noticeable effects. Wells constructed following the implementation of this regulation are expected to have higher well integrity, which should make them cheaper to plug. Among the 428 wells with age data, 65 (15.2%) were drilled after 1985. SI Figure S4 shows the distribution of wells based on completion year for the subset of wells drilled between 1975 and 1995, as well as the average plugging costs by completion year. As expected, the data suggest that most of the expensive projects involved older wells.

Kansas is divided into four conservation districts (SI Figure S5). Average plugging costs are cheapest in District 3, located in the eastern part of the state. Oil drilling first began in eastern Kansas and moved west, such that the oldest and the shallowest wells are in District 3 (SI Table S3). The average well depth in District 3 is 636 feet, as compared with an average depth of 4029 feet in District 1 (located in southwest Kansas). Additionally, well age data are not available for 97% of the wells in District 3, suggesting that many of the wells in this district are older and were drilled before well permitting regulations were introduced. Thus, a well's district is likely to be correlated with plugging cost through a number of spatially correlated variables including well depth and well age. Although both are important factors affecting plugging costs, well depth is likely to have a stronger effect, as suggested by the larger correlation coefficient. Other spatially correlated variables that we are unable to observe in the data include district-specific plugging regulations and the degree of competition in the service provider market in each region.

Oil price is another factor likely to affect plugging costs. Oil prices fluctuated between $50 and $70 per barrel (2014$) between 1996 and 2003 (see SI Figure S6), then increased steadily.

Factors Affecting P&A Costs: Regression Results. Table 2 presents results from two regressions. Model (1) only includes well depth and district as explanatory variables. Because many of the wells in our data set were drilled before permitting requirements were introduced, the majority of the wells in the sample do not have a known drill date. So as not to lose these observations, but still estimate the impact of age, in Model (2) we include an indicator for whether age is known, and an interaction of the indicator with the age of the well. We also include oil price, plugging year, contract size, district dummies, well type, and land use.

We find that depth is positively correlated with plugging cost. A 1000-foot increase in depth is associated with a 34.4% increase in plugging costs (for the average well with plugging costs of $5,020, this implies a $1,720 increase). Wells whose age is known are 75.4% cheaper to plug relative to wells without age information, presumably because they are younger, having been drilled after well permitting regulations were introduced. Older wells are more expensive to plug: for those with age information, an additional year of age implies a 0.4% increase in plugging cost. As a well ages, extreme corrosion can cause its steel casing to collapse, and the cement used to seal well annuli can also shrink. Any uncemented or damaged casing must be recovered from the wellbore. If this is not possible, the casing is perforated and cement is squeezed through the perforations into the annular spaces. Perforation is an expensive process and adds significantly to total plugging costs.

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Table 2. Determinants of Plugging Costs[a]

variables	model (1) log(plugging cost)		model (2) log(plugging cost)	
depth (1000 ft)	0.344***	(0.022)	0.309***	(0.020)
I(age known)			−0.754***	(0.068)
I(age known) × age			0.004*	(0.002)
oil price			0.016***	(0.001)
plugging year			−0.076***	(0.003)
contract size			−0.002***	(0.000)
I(district = 2)	0.924***	(0.131)	0.535***	(0.118)
I(district = 3)	0.259*	(0.127)	−0.415***	(0.119)
I(district = 4)	0.458***	(0.110)	0.389***	(0.100)
I(type = oil)			−0.101***	(0.027)
% urban			0.003*	(0.001)
% water			0.011***	(0.003)
% agriculture			−0.004***	(0.001)
constant	7.750***	(0.135)	159.252***	(5.540)
observations	5,838		5,838	
adj. R-squared	0.210		0.366	

[a]Note: Observations are orphan wells plugged by the state of Kansas from 1996 to 2013. The dependent variable is the log of plugging cost. Standard errors are in parentheses. Statistical significance is denoted by *** $p < 0.001$, ** $p < 0.01$ and * $p < 0.05$.

Conversations with representatives from the KCC and industry suggest that oil prices are positively correlated with plugging cost. Well plugging service providers also provide contract services for oil production activities; thus, when oil prices and oil production are high, there is more competition and therefore higher prices for well plugging services, since providers shift from plugging wells to drilling wells. We observe this in our results, where a $1 per barrel increase in oil price is correlated with a 1.6% increase in plugging costs.

Well plugging costs are lower over time—a well plugged in a given year is, on average, 7.6% cheaper to plug than a well plugged the year before. This year trend controls for changes over time, but the coefficient should be interpreted with caution. For example, the decrease over time could be due to new plugging technologies that reduce cost. Alternatively, the KCC could have targeted the wells that presented the greatest environmental hazard in the early years of the program, such that the wells plugged later are cheaper to plug.

The hydrocarbon reservoir formations in different locations could have very different physical, chemical, and biological properties, such as salinity and indigenous microbial species,[48] which could impact well conditions. Thus, wells in one area may be subject to a greater risk of corrosion than in others, and these would be more expensive to plug. Further, competition can vary spatially: the market for service providers may be more competitive, and therefore prices would be lower, in some districts than in others. The indicators capturing the different districts control for similarities within the districts.

Larger contracts are associated with lower per-well plugging costs. An additional well in the contract is associated with a 0.2% decrease in plugging cost. This could be driven by economies of scale: with larger contracts, certain fixed costs, such as transportation costs, are spread over a larger number of wells. Alternatively, contractors with the lowest costs could be the ones taking on the largest projects. However, while statistically significant, the magnitude of the effect on P&A costs is not very large.

P&A costs for wells on urban land are more expensive than for those on barren land, grassland, wetlands, or forested land. Additionally, the proximity of a well to water increases P&A costs. We speculate that this could reflect the additional water protection or water monitoring measures required.

On average, gas wells are 10.1% more expensive to plug than oil wells. A possible explanation could be the different pressure gradients in each of these types of wellbores, where gas wells have higher wellbore pressures than oil wells and require more expensive plugging methods.

We caution against using these estimates from Kansas to estimate plugging costs elsewhere, particularly given that plugging costs in Kansas are on average less expensive than those in other states. Nonetheless, the methodology we demonstrate here can be replicated in other jurisdictions. Identifying the statistical correlation between cost factors and plugging costs, as we have done here, is a plausible method for estimating plugging costs for individual wells depending on their characteristics, or for estimating the total cost of plugging any given sample of inactive wells elsewhere in the country. However, the data needs for such an effort are not trivial. At present, many states do not maintain comprehensive and easily accessible data on historical P&A costs per well, well characteristics, or the current population of inactive wells in the state. Previous legislative audits have also commented on this data

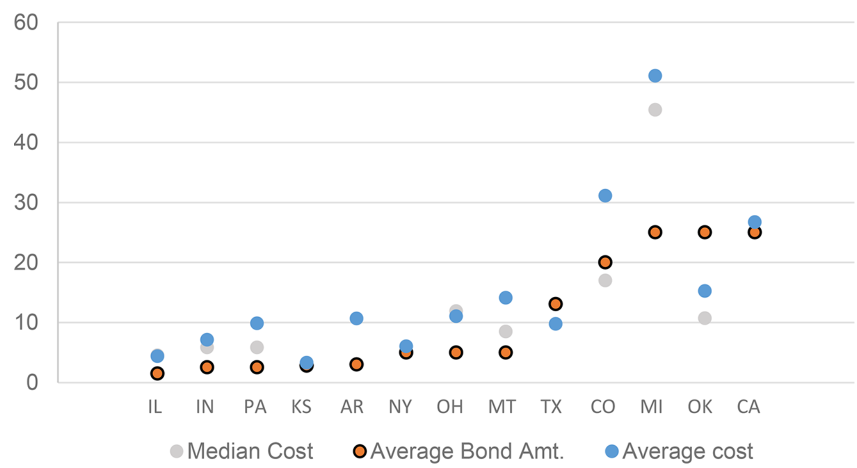

Figure 1. Average Costs ($'000) Exceed Average Bond Amounts ($'000) in 11 of 13 States Studied.

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deficiency.[37,38] With better data, states would be able to more accurately estimate the cost of decommissioning the wells at risk of becoming orphaned and those that pose elevated environmental risk, enabling a better understanding of the financial liability associated with the orphaned wells under their jurisdiction.

State Expenditures on Plugging Orphaned Wells Exceed Bond Amounts. We compare the average P&A costs in 13 states against the bond amounts that operators are required to provide to the state. Our results provide evidence that average P&A expenditures on orphaned wells exceed bond amounts, and therefore revenues collected via bonds are insufficient for the state to cover the cost of plugging orphaned wells under their jurisdiction. The bond amounts presented in Figure 1 are extracted from each state's regulations. In cases where bond amounts are calibrated by well depth (i.e. larger bonds are required for deeper wells), we calculate average bond amounts using estimates of the average well depth of inactive wells in the state. Note that in most states, operators are not required to post a separate bond to cover site reclamation costs; these costs are expected to be covered by the well bond. SI Table S5 provides a full description of our methodology for deriving these average bond amounts. The cost figures used for the comparison are nominal cost figures.

Ideally, rather than (or in addition to) comparing average costs against average bond amounts, plugging costs per well should be compared against the bond amount for each individual well. Even if average bonds were set to average costs, there may still be wells whose plugging costs far exceed the amount of the bond attached to them. However, we were only able to obtain per-well plugging costs for a significant population of wells for seven of the 13 states in our study. For these seven states, we present the results of a more detailed cost-versus-bond comparison below.

Our data on the costs of plugging orphaned wells reveal that average costs exceed average bond amounts in 11 of the 13 states, and median costs exceed average bond amounts in six of the nine states for which the appropriate data are available. Average bond amounts are more than sufficient to cover the cost of the cheapest projects; however, they fall far short of the most expensive projects (SI Table S5).

How frequently costs exceed bonds is useful for understanding the frequency with which states bear the burden of paying for P&A. In five of seven states for which data on per-well costs were available, more than half of the orphaned wells cost more to plug than the average bond amount. This suggests that in order to P&A orphaned wells, regulators in most states can currently expect to bear a burden of P&A costs in excess of bond amounts for the majority of orphaned wells. Note that we are not able to compare P&A costs against the actual bond attached to each well, since such detailed data on bond amounts are not available. Instead, we can only compare costs against the average bond amount that we estimate based on the bonding regulations and average well depth in each state (SI Table S5). In Pennsylvania, 98% of the wells (2824 of 2866) cost more to plug than the average bond; in Illinois, 97% (267 of 289); in Michigan, 94% (267 of 289); in Indiana, 79% (279 of 380); and in Montana, 75% (235 of 312). In Kansas, close to half of the wells cost more to plug than the bond (47%, 2725 of 5838 wells). Oklahoma was the only state where the wells that cost more to plug were a small percentage of the total number of wells plugged (16%, 26 of 165 wells). The state's financial burden can be exacerbated by very expensive projects. In Pennsylvania, the 99th percentile of projects cost at least $66,516—exceeding the bond by more than $64,000 for each project. In total, these 31 wells cost $2.98 million more than the total estimated amount of their bond.

To make up the shortfall between bonds and P&A costs, many states rely on a combination of permit and annual fees from industry, legislative appropriations, severance taxes, and environmental cleanup funds (see SI Table S1).

The difference between bonds and costs that we have presented here can be exacerbated by the use of blanket bonds. In most states, an operator has the option of filing a blanket bond for all of its wells in the jurisdiction, rather than posting individual bonds for each well. The blanket bond effectively offers operators a "quantity discount." In Michigan, blanket bonds can be posted for a maximum of 100 wells. Bonds for 100 wells with a depth of less than 2000 feet would cost $10,000 per well for a total of $1 million; however, a blanket bond for these 100 wells would cost only 10% of that amount. We do not have data on which operators posted blanket bonds as opposed to individual bonds. Therefore, it is important to note that our analysis only compares P&A costs against average *individual* well bonds and therefore is a lower-bound estimate of the liability held by the state.

A second important issue is that our data describe the states' costs of plugging *orphaned* wells, which may be higher or lower than the costs incurred by private operators. Why might orphaned wells be cheaper to plug? According to a representative from the KCC, government contracts may be less expensive than private contracts as the former are less time-sensitive and also solicit multiple bids before deciding on the most cost-effective option. In addition, orphaned wells are typically older and shallower than wells with an owner, and may therefore be cheaper to plug because they are shallower. On the other hand, orphaned wells may also be more expensive to plug, since many are from an earlier era of oil drilling and may be in worse condition. In addition, the state may not have comprehensive information on well construction for orphaned wells and may thus need to spend more on diagnostic work to assess the scope of P&A work to be done.

Furthermore, the average cost of plugging an orphaned well may be higher because of a selection issue: setting aside nonmonetary reasons to plug wells (e.g., reputational and license-to-operate concerns), a firm only has an incentive to plug a well when the bond exceeds the P&A costs, which means that the orphaned wells that states are left with are likely more expensive. This selection bias could be driving the pattern we observe in Figure 1, where state expenditures on orphaned wells tend to be higher in states with higher bonds. Therefore, we expect that states with higher bonds would be left with fewer wells, but the wells left would be more expensive to plug. Without data on all plugging costs, we do not know what percent of wells fall below the bond amount in each state. (Unobserved variables could also be driving this pattern: statewide conditions could make plugging more expensive, for example, deeper wells could lead states to have higher bond amounts.)

All of the above factors considered, and in the absence of private sector cost data, it is challenging to assess whether P&A costs for orphaned wells are likely to be representative of, higher than, or lower than P&A costs for all wells, including those plugged by operators. Nonetheless, our results still present compelling and policy-relevant evidence that average bond amounts have generally been insufficient to cover the average cost of plugging orphaned wells.

Finally, the average costs reported here are not necessarily an accurate predictor of the costs of plugging future wells. Most of the wells currently being drilled are horizontal wells, whereas

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most of the wells in this study are vertical wells, since the widespread use of horizontal drilling is a relatively recent development in the industry. Insights from conversations with state regulators and an industry representative suggest that the unit costs of plugging horizontal wells should not be different from that of plugging vertical wells, because only the vertical portion of the well is plugged. However, if horizontal shale gas wells are deeper then total costs per well would be expected to be greater.

■ DISCUSSION

As oil and gas development continues to grow in the U.S., ensuring that inactive wells are properly plugged by their operators is essential for protecting the public from the human health, environmental, and financial costs associated with these wells. Our research shows that bonding requirements in the majority of states we examined have been insufficient to cover the cost of plugging the average orphaned well. The result is that the state must draw on other revenues to cover the costs of plugging, and the public must bear the environmental cost of wells that remain unplugged due to a lack of state funds.

Should bond amounts required for oil and gas wells be raised? In theory, bond amounts could be set equal to the maximum potential cost so as to prevent situations where costs cannot be fully covered by the operator.[21] However, in practice, it is not necessarily the case that bonds should equal the maximum potential P&A cost.[19] Even if a bond is lower than P&A costs, firms still have an incentive to plug if there are litigation costs or reputational costs from not plugging. Furthermore, requiring a bond imposes a liquidity constraint on small operators,[20,21] although this can be partially offset by third-party surety or insurance companies. Another theoretical possibility, which we have highlighted above, is to adjust bond amounts according to projected liabilities. This approach has been used in the case of bonding requirements for surface mines under the Surface Mining Control and Reclamation Act in the U.S.[25] However, this approach adds to the cost of enforcing bonding regulations, as it would require more time and resources to project the likely costs of plugging, and to negotiate over bond amounts.[18]

While there are many factors to consider when determining the optimal bond amount, we show strong evidence that the current bonds are not sufficient to finance end-of-life expenditures for orphaned wells. If the regulator's goal is to ensure sustainable funding for plugging of orphan wells, then our results suggest that bonds are too low. Discouragingly, bond amounts for individual wells on Bureau of Land Management (BLM) land have not been updated since 1960.[36,37] On the other hand, in recent years, some states have increased their bonding requirements or have considered this possibility, including West Virginia, Maryland,[18] Wyoming,[49] Kentucky,[50] Missouri,[51] and Pennsylvania.[52] If this course of action is not possible, states should consider developing a fund for paying off funding shortfalls, using special assessments, severance taxes, or other revenue sources. In addition, the option for operators to post blanket bonds instead of individual well bonds should be reviewed. As has been highlighted in this paper and elsewhere in the literature,[18] the blanket bond option effectively provides operators a large quantity discount on bonds for a large number of wells, further exacerbating the difference between P&A costs and the bond on each well.

Furthermore, by requiring the same bond amount for all wells, there will be some operators that pay too much and some too little, given the large variation in P&A costs. This concern could be alleviated if bonds were to vary by factors that influence P&A cost, such as the ones we have found to be significant in our analysis (e.g., well depth, location, and proximity to groundwater). A few states already calibrate their bond amounts by well depth (see SI Table S4), though many do not. In addition, agencies could calibrate bond amounts with respect to an operator's compliance record, increasing bond amounts for operators that have a poor record. This could improve the incentive the incentive for operators to comply with environmental requirements.

It should be noted that our analysis and recommendations only partially address the issue of inactive and orphaned wells. Ensuring the adequacy of bonding regulations helps prevent the orphaning of wells drilled in the future. However, as noted in the introduction and as demonstrated by the incomplete data on well age in our Kansas data set, the majority of orphaned wells are legacy wells, some of which are not even accounted for in state records. The issue of identifying, managing, and funding proper P&A for these wells has been discussed in other publications.[9,38,53]

We have identified a number of questions that could inform future research. First, what is the optimal level at which state regulators should set bond amounts? We provide evidence that bonds do not cover plugging costs for orphaned wells, and that there is variability in P&A costs that would be better addressed by well-specific bonds. However, research on determining the optimal bond amount,[54] in light of the current liability regime, the trade-off between simplicity and well-specific bonds, and the impacts of liquidity constraints,[55] will be important to inform policymakers as they update their regulations. Second, how does increasing bond requirements change the rate at which wells are orphaned? In theory, this should reduce orphaning rates; however, to our knowledge, how well orphaning is affected by factors including bonding regulations has not been tested empirically. Third, how are plugging programs currently being financed across the states, and to what extent are these funding mechanisms meeting the needs of the programs? For instance, informal conversations with state agency representatives have revealed that a dependence on industry fees results in a decrease in plugging revenues during periods of low production—exactly when the number of orphaned wells would be expected to increase due to poorer financial performance in the industry.[56] SI Table S1 shows how plugging programs are currently financed in a number of states. Fourth, how prevalent is the use of blanket bonds, and why do states continue to offer this option to operators given how much it exacerbates the funding shortfall? Finally, what has enabled certain states to successfully introduce reforms to their bonding regulations while other states have not? The insights from such a study could inform the adoption of similar reforms in other states, and ultimately help strengthen regulatory protections against the environmental risk of inactive wells.

■ ASSOCIATED CONTENT

Supporting Information

The Supporting Information is available free of charge on the ACS Publications website at DOI: 10.1021/acs.est.7b06609.

A list of sources of funding for plugging orphaned wells in selected states, a description of the five data sets used for the regression analysis of factors affecting plugging costs, summary tables and figures describing these data, descriptions of the data obtained from the 13 states in our study on their orphaned well plugging costs, a more detailed comparison of plugging costs and average bond amounts (these are the data underlying Figure 1 in the article), and a test of multicollinearity for our regression analysis(PDF)

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The authors declare no competing financial interest.

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United States Government Accountability Office
Report to Congressional Requesters

September 2019

OIL AND GAS

Bureau of Land Management Should Address Risks from Insufficient Bonds to Reclaim Wells

GAO-19-615

GAO Highlights

Highlights of GAO-19-615, a report to congressional requesters

Why GAO Did This Study

The oil and natural gas produced from wells on federal lands are important to the U.S. energy supply and bring in billions in federal revenue each year. However, when wells are not properly managed, the federal government may end up paying to clean up the wells when they stop producing. Specifically, wells on federal lands that an operator does not reclaim and for which there are no other liable parties fall to BLM to reclaim (restore lands to as close to their original natural states as possible). These wells become orphaned if the operator's bond held by BLM is not sufficient to cover reclamation costs. BLM regulations set minimum bond values at $10,000 for all of an operator's wells on an individual lease, $25,000 for all of an operator's wells in a state, and $150,000 for all of an operator's wells nationwide.

GAO was asked to review the status of oil and gas bonding for federal lands. This report (1) describes the value of bonds for oil and gas wells in 2018 compared to 2008, and (2) examines the extent to which BLM's bonds ensure complete and timely reclamation and thus prevent orphaned wells. GAO analyzed agency data on bonds and wells and interviewed BLM officials.

What GAO Recommends

Congress should consider giving BLM the authority to obtain funds from operators to reclaim orphaned wells, and requiring BLM to implement a mechanism to do so. GAO also recommends that BLM take steps to adjust bond levels to more closely reflect expected reclamation costs. BLM concurred. BLM did not concur with a proposed recommendation to develop a mechanism to obtain funds, citing lack of authority. GAO changed it to a matter for Congressional consideration.

View GAO-19-615. For more information, contact Frank Rusco at (202) 512-3841 or ruscof@gao.gov.

September 2019

OIL AND GAS

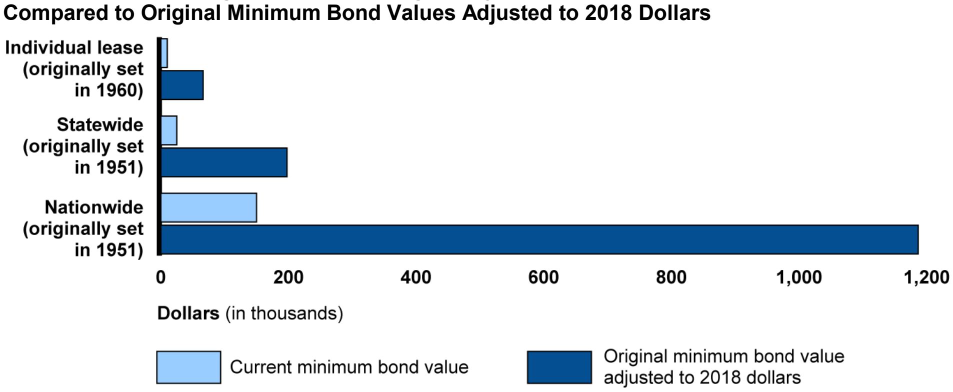
Bureau of Land Management Should Address Risks from Insufficient Bonds to Reclaim Wells

What GAO Found

The average value of bonds held by the Bureau of Land Management (BLM) for oil and gas wells was slightly lower on a per-well basis in 2018 ($2,122) as compared to 2008 ($2,207), according to GAO's analysis of BLM data. The total value of bonds held by BLM for oil and gas operations increased between these years, as did the number of wells on federal land.

Bonds held by BLM have not provided sufficient financial assurance to prevent orphaned oil and gas wells (wells that are not reclaimed by their operators and, among other things, whose bonds were not sufficient to cover remaining reclamation costs, leaving BLM to pay for reclamation). Specifically, BLM identified 89 new orphaned wells between July 2017 and April 2019, and BLM offices identified to GAO about $46 million in estimated potential reclamation costs associated with orphaned wells and with inactive wells that officials deemed to be at risk of becoming orphaned in 2018. In part, bonds have not prevented orphaned wells because bond values may not be high enough to cover the potential reclamation costs for all wells under a bond, as may be needed if they become orphaned. GAO's analysis indicates that most bonds (84 percent) that are linked to wells in BLM data are likely too low to reclaim all the wells they cover. Bonds generally do not reflect reclamation costs because most bonds are set at their regulatory minimum values, and these minimums have not been adjusted since the 1950s and 1960s to account for inflation (see figure). Additionally, these minimums do not account for variables such as number of wells they cover or other characteristics that affect reclamation costs, such as well depth. Without taking steps to adjust bond levels to more closely reflect expected reclamation costs, BLM faces ongoing risks that not all wells will be completely and timely reclaimed, as required by law. It falls to BLM to reclaim orphaned wells, but the bureau does not assess user fees to cover reclamation costs, in part because it believes it does not have authority to do so. Providing such authority and developing a mechanism to obtain funds from operators for such costs could help ensure that BLM can completely and timely reclaim wells.

Bureau of Land Management Current Regulatory Minimum Oil and Gas Bond Values Compared to Original Minimum Bond Values Adjusted to 2018 Dollars



Source: GAO analysis of Bureau of Land Management data. | GAO-19-615

Contents

Abbreviations

AFMSS	Automated Fluid Minerals Support System
BLM	Bureau of Land Management
EPAct 2005	Energy Policy Act of 2005
LR2000	Legacy Rehost 2000
OGOR	Oil and Gas Operations Report

U.S. GOVERNMENT ACCOUNTABILITY OFFICE
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September 18, 2019

The Honorable Raúl M. Grijalva
Chairman
Committee on Natural Resources
House of Representatives

The Honorable Alan S. Lowenthal
Chairman
Subcommittee on Energy and Mineral Resources
Committee on Natural Resources
House of Representatives

Oil and natural gas produced from wells on federal lands are important to the U.S. energy supply and bring in billions in federal revenue each year. However, when oil and gas wells are not properly managed, the federal government may end up paying to clean up the wells when they stop producing. According to the Department of the Interior's Bureau of Land Management (BLM), at the end of fiscal year 2018, BLM oversaw private entities operating over 96,000 oil and gas wells on leased federal lands. BLM is responsible for managing onshore federal oil and gas resources and determining requirements for operators to reclaim leased lands, which BLM defines as restoring lands to as close to their original natural states as possible.[1] The oil and gas industry's boom-and-bust cycles can lead operators to drill wells when prices for oil and gas are high but can contribute to bankruptcies when prices are low. As a result, operators may not always have the resources to reclaim lands around wells that have been degraded by drilling and production.[2] When wells are not fully

[1]BLM is responsible for issuing leases for private entities to develop oil and gas resources on and under roughly 700 million acres of (1) BLM land, (2) other federal agencies' land, and (3) private land where the federal government owns the mineral rights. According to BLM, approximately 26 million acres were leased for oil and gas operations at the end of fiscal year 2018. BLM's regulatory responsibilities also extend in part to development of oil and gas on Indian trust and restricted lands, but those lands and programs are outside the scope of this report.

[2]For the purposes of this report, "operator" refers to lessees, owners of operating rights, and operators of an oil or gas operation, unless indicated otherwise. We use the term "reclamation" to refer to all of the actions and costs to reclaim a well, including well plugging and surface reclamation, and to restoring any lands or surface waters adversely affected by oil and gas operations.

reclaimed, there may be risks of leaking methane or groundwater contamination, among other things.[3]

BLM uses bonds to reimburse at least some of the costs of well reclamation in the event that operators or other liable parties do not reclaim wells. The Mineral Leasing Act of 1920, as amended, requires that federal regulations ensure that an adequate bond is established before operators begin preparing land for drilling to ensure complete and timely reclamation of the land, among other things.[4] BLM regulations set minimum bond values: $10,000 for all of an operator's wells on an individual lease (known as an individual lease bond), $25,000 for all of an operator's wells in a state (known as a statewide bond), and $150,000 for all of an operator's wells nationwide (known as a nationwide bond).[5] In January 2010, we reported on the number and value of bonds BLM held for oil and gas operations for fiscal years 1988 through 2008 and the value of individual lease, statewide, and nationwide bonds as of December 2008.[6] These bonds are designed to help prevent or reduce taxpayer losses because the bond money may be used to reclaim wells when operators or other liable parties do not. When the bonds covering those wells are insufficient to cover reclamation expenses, and there are no other responsible or liable parties to do so, wells are considered "orphaned."

Federal laws and BLM regulations and policies contain requirements aimed at managing BLM's potential oil and gas well liabilities and

[3]In this report, we refer to a well and the site surrounding it as a well.

[4]Specifically, BLM "shall, by rule or regulation, establish such standards as may be necessary to ensure that an adequate bond, surety, or other financial arrangement will be established prior to the commencement of surface-disturbing activities on any lease, to ensure the complete and timely reclamation of the lease tract, and the restoration of any lands or surface waters adversely affected by lease operations after the abandonment or cessation of oil and gas operations on the lease." 30 U.S.C. § 226(g).

[5]BLM coordinates with the Forest Service regarding oil and gas development on National Forest System lands. Where oil or gas development involves surface disturbance of National Forest System lands, the Forest Service must assess whether the existing BLM bond is adequate to meet the estimated cost to the Forest Service to reclaim those surface areas to be disturbed and to restore any lands or surface waters adversely effected by lease operations. If the Forest Service determines that bond is not adequate, the operator has the options of increasing the BLM bond amount or obtaining a separate bond to meet such estimated costs.

[6]GAO, *Oil and Gas Bonds: Bonding Requirements and BLM Expenditures to Reclaim Orphaned Wells*, GAO-10-245 (Washington, D.C.: Jan. 27, 2010).

preventing orphaned wells, including through ongoing oversight of wells and bonds provided by operators. For example, BLM's well review policy calls for field offices to, among other things, periodically review all inactive wells to determine whether they are capable of producing oil or gas or have a future beneficial use and, if not, have operators submit plans to reclaim the wells.[7] In May 2018, we reported on BLM's challenges in implementing these reviews, including differing understandings among field offices of the specific actions that constitute a well review.[8] In that report, we recommended that BLM develop and communicate specific instructions on what actions constitute a well review for annual reporting purposes. BLM concurred with this recommendation, and officials told us they are developing new reporting requirements.

Similar to its well review policy, BLM has a bond adequacy review policy that calls for BLM to regularly review bonds when certain events occur or periodically. Based on these reviews, BLM is to seek to increase bonds as necessary to ensure they reflect risks posed by the operator.[9] In our May 2018 report, we also reported on BLM's challenges in implementing bond adequacy reviews and made recommendations to improve their implementation.[10] In that report, we recommended that BLM strengthen its approach to monitoring field offices' implementation of the bond adequacy review policy, such as by collecting and analyzing data on performance indicators and ensuring the quality of those data. BLM concurred with this recommendation, and officials told us they are working on revising their guidance on data validation and are implementing quality reviews of their data.

You asked us to review issues related to bonds for oil and gas wells on federal lands. This report (1) describes the value of bonds for oil and gas wells in 2018 compared to 2008, and (2) examines the extent to which BLM's bonds ensure complete and timely reclamation and thus prevent orphaned wells.

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[7]Bureau of Land Management, *Instruction Memorandum 2012-181* (Sept. 5, 2012).

[8]GAO, *Oil and Gas Wells: Bureau of Land Management Needs to Improve Its Data and Oversight of Its Potential Liabilities*, GAO-18-250 (Washington, D.C.: May 16, 2018).

[9]These bond adequacy reviews use a points-based system to examine aspects of an operator's wells (such as its number of wells idle for at least 7 years), compliance history (such as its number of incidents of drilling without approval), and reclamation stewardship (such as its number of reclamation incidents of noncompliance issued in the last 5 years).

[10]GAO-18-250.

To describe the value of bonds for oil and gas wells in 2018 compared to 2008, we analyzed oil and gas well data from BLM's Automated Fluid Minerals Support System (AFMSS) as of May 2018 and data on bonds from BLM's Legacy Rehost 2000 (LR2000) system as of May 2018. We compared these data to the 2008 data from these systems that we reported in 2010.[11] We matched the May 2018 data from the two systems based on the bond number—a variable in both systems—to identify how many wells were covered by each bond and to determine the average bond value per well for each bond category. To assess the reliability of these AFMSS and LR2000 data elements, we reviewed agency documents, met with relevant agency officials, and performed electronic testing. We found these data to be sufficiently reliable for our purposes.

To examine the extent to which BLM's bonds ensure complete and timely reclamation and thus prevent orphaned wells, we analyzed several sources of data, including AFMSS well data, LR2000 bond data, Office of Natural Resources Revenue's Oil and Gas Operations Report (OGOR) well production data, and well reclamation cost estimates from proofs of claim that BLM files with the Department of Justice when an operator files for bankruptcy.[12] First, we examined whether bonds are sufficient to cover potential reclamation costs for the wells they cover. To do this, we analyzed cost estimates on proofs of claim and identified typical high- and low-cost well reclamation scenarios. We then compared the cost scenarios to the average bond value available per well, for each bond, calculated using bond values in LR2000 and the number of wells covered by each bond in AFMSS. Next, we examined a subset of wells that are at increased risk of becoming orphaned and whether bonds are sufficient to cover their potential reclamation costs. To do this, we used OGOR production data to identify wells that had not produced since at least June 2008 and that met several other criteria. For those at-risk wells, we compared reclamation cost scenarios to the average bond value available for each—calculated by dividing bond value by the number of at-risk wells covered by the bond—using well data from AFMSS and bond value data from LR2000. To assess the reliability of the AFMSS, LR2000, and OGOR data elements we used, we reviewed agency documents, met with relevant agency officials, and performed electronic testing. We found these data to be sufficiently reliable for our purposes.

[11]GAO-10-245.

[12]The Office of Natural Resources Revenue manages and ensures full payment of revenues owed for the development of the nation's energy and natural resources offshore, on the Outer Continental Shelf, and onshore, on federal and Indian lands.

In addition, we examined the number of orphaned wells, comparing the number of orphaned wells identified by BLM as of April 2019 to those identified by BLM as of July 2017 and 2009, the two previous times we reported on orphaned wells.[13] To assess the reliability of the 2019 orphaned well list, we reviewed agency documents and met with relevant agency officials. Though we identified shortcomings with these data, which we discuss in the report where appropriate, we nevertheless found these data to be sufficiently reliable for the purpose of describing the orphaned wells BLM has identified.

To understand how BLM manages bonds, we reviewed BLM's policies and interviewed officials from four BLM state offices and four BLM field offices.[14] We selected these state and field offices because they were responsible for managing the largest numbers of wells on federal land. We also interviewed officials from BLM's headquarters office in Washington, D.C. Findings from the selected BLM offices cannot be generalized to offices we did not interview, but they provide a range of views. Appendix I provides additional information on our scope and methodology.

We conducted this performance audit from January 2018 to September 2019 in accordance with generally accepted government auditing standards. Those standards require that we plan and perform the audit to obtain sufficient, appropriate evidence to provide a reasonable basis for our findings and conclusions based on our audit objectives. We believe that the evidence obtained provides a reasonable basis for our findings and conclusions based on our audit objectives.

Background

Life Cycle of Oil and Gas Wells

Oil and gas exploration and production involves disturbing lands in several ways. For example, when operators drill oil and gas wells, they typically remove topsoil and construct a well pad, where the drilling rig will be located. Other equipment on-site can include generators and fuel tanks. In addition, reserve pits are often constructed to store or dispose of water, mud, and other materials that are generated during drilling and

[13]See GAO-10-245 and GAO-18-250.

[14]The four selected BLM state offices are California, New Mexico, Wyoming, and Utah. The four selected BLM field offices are Bakersfield, Buffalo, Carlsbad, and Farmington.

production, and roads and access ways are often built to move equipment to and from the wells.

Once wells cease production, which may occur many decades after they are drilled, they can become inactive. Inactive wells have the potential to create physical and environmental hazards if operators do not properly reclaim them, a process that may involve plugging the well, removing structures, and reshaping and revegetating the land around the wells. For example, inactive wells that are not properly plugged can leak methane into the air or contaminate surface water and groundwater. Well sites that are not properly reclaimed can contribute to habitat fragmentation and soil erosion, and equipment left on-site can interfere with agricultural land use and diminish wildlife habitat.

Costs for well reclamation vary widely and are affected by factors such as the depth of the well. Although BLM does not estimate reclamation costs for all wells, it has estimated reclamation costs for thousands of wells whose operators have filed for bankruptcy. Based on our analysis of these estimates, we identified two cost scenarios: low-cost wells typically cost about $20,000 to reclaim, and high-cost wells typically cost about $145,000 to reclaim.[15]

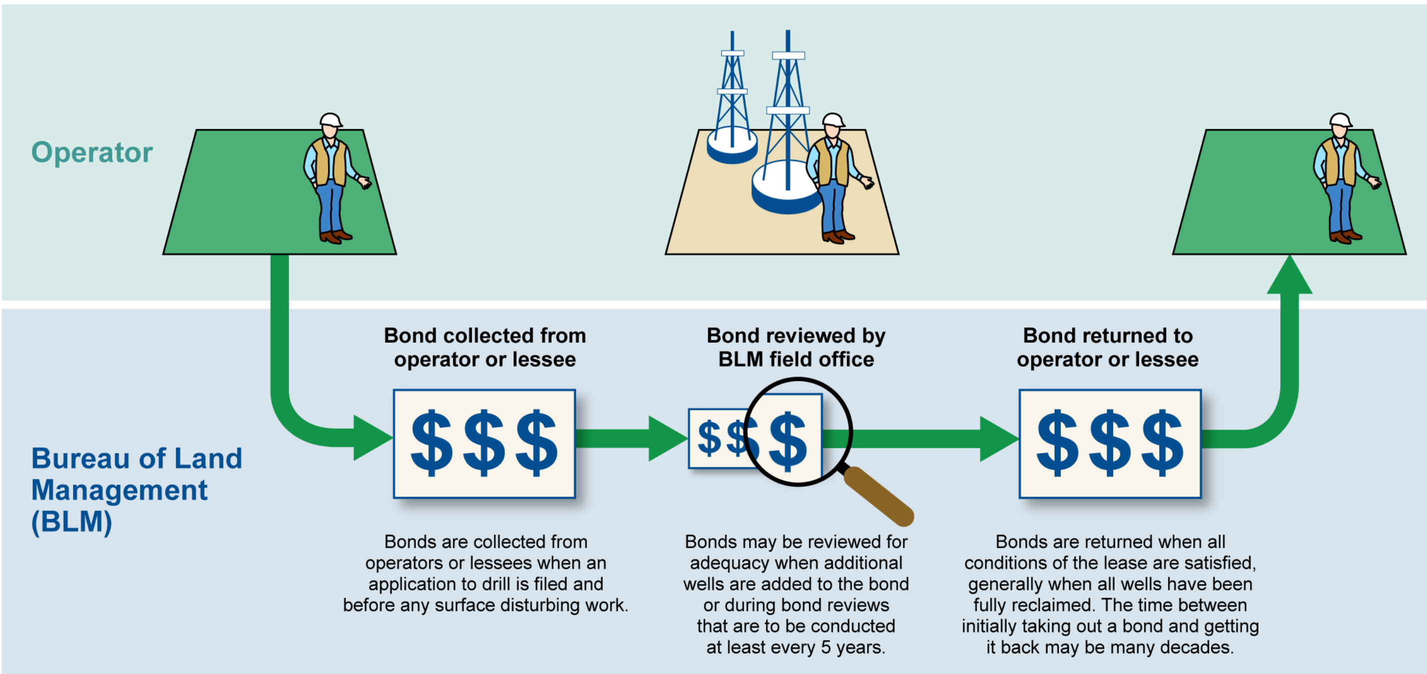
BLM's Bonding Regulations and Policies

As shown in figure 1, BLM regulations or policies outline how BLM is to initially collect bonds from operators, review bonds, and ultimately return the bond to the operator or use it to cover costs of reclamation.

[15]Based on our analysis of BLM reclamation cost estimates, the costs to reclaim wells were clustered into distinct groups: relatively low-cost and relatively high-cost wells. Due to this pattern of clustering and a wide variation in reclamation costs, we used these data as a basis to define two scenarios of potential reclamation costs for any individual well. Although we do not have information about the reclamation costs for all BLM wells, or the extent to which the proofs of claim sample is representative of all BLM wells, we consider these two scenarios to reflect a reasonable range of potential reclamation costs for a typical well.

The low-cost scenario is based on the 25th percentile of average well reclamation costs in proofs of claim, and the high-cost scenario is based on the 75th percentile. These scenarios do not encompass the complete range of BLM's well reclamation cost estimates. For example, on the low end, the 5th percentile average was about $15,000, and the lowest average estimate was $3,096. On the high end, the 95th percentile average was about $174,000, and the highest estimate was $603,000. Reclamation costs can vary based on a number of factors, such as well depth or location.

Figure 1: Life Cycle of a Bureau of Land Management Bond for Oil and Gas Operations



Source: GAO analysis of Bureau of Land Management information. | GAO-19-615

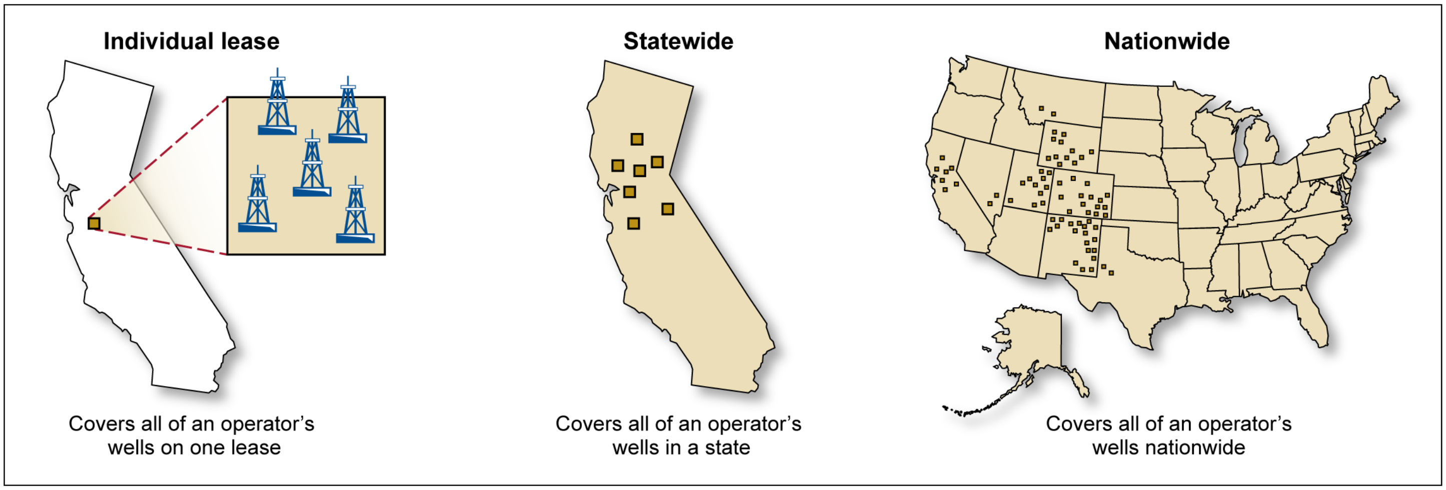
Bonds collected from operator. BLM regulations require operators to submit a bond to ensure compliance with all of the terms and conditions of the lease, including, but not limited to, paying royalties and reclaiming wells.[16] BLM regulations generally require operators to have one of the following types of bond coverage:[17]

[16] 43 C.F.R. § 3104.1(a).

[17] Other bonds include unit operator bonds that cover all operations conducted on leases within a specific unit agreement and bonds for leases in the National Petroleum Reserve in Alaska. Unit agreements refer to multiple lessees who unite to adopt and operate under a single plan for the development of any oil or gas pool, field, or like area. The amount of a unit operator bond is determined on a case-by-case basis by BLM officials, and the minimum amount of a National Petroleum Reserve in Alaska bond is set in regulation—not less than $100,000 for a single lease or not less than $300,000 for a reserve-wide bond (submitted separately or as a rider to an already existing nationwide bond).

- individual lease bonds, which cover all of an operator's wells under one lease;[18]
- statewide bonds, which cover all of an operator's leases and operations in one state;[19] or
- nationwide bonds, which cover all of an operator's leases and operations nationwide.[20] (See figure 2.)

Figure 2: Bureau of Land Management Individual Lease, Statewide, and Nationwide Bonds for Oil and Gas Operations



Source: GAO analysis of Bureau of Land Management information. | GAO-19-615

BLM can accept two types of bonds: surety bonds and personal bonds. A surety bond is a third-party guarantee that an operator purchases from a private insurance company approved by the Department of the Treasury. The operator pays a premium to the surety company that can vary depending on various factors, including the amount of the bond and the assets and financial resources of the operator. If operators fail to reclaim

[18]An individual lease bond posted by a lessee may cover all operators on a lease. Otherwise, each operator on a lease must provide a separate bond covering just the wells operated by that operator. As we previously reported, according to BLM officials, most leases have only one operator. See GAO, *Oil and Gas Bonds: BLM Needs a Comprehensive Strategy to Better Manage Potential Oil and Gas Well Liability*, GAO-11-292 (Washington, D.C.: Feb. 25, 2011).

[19]A statewide bond posted by a lessee can cover all well operators with the consent of the company providing the bond.

[20]A nationwide bond posted by a lessee can cover all well operators with the consent of the company providing the bond.

their wells, the surety company is responsible for paying BLM up to the amount of the bond to help offset reclamation costs.

A personal bond must be accompanied by one of the following financial instruments:

- certificates of deposit issued by a financial institution whose deposits are federally insured, granting the Secretary of the Interior full authority to redeem it in case of default in the performance of the terms and conditions of the lease;
- cashier's checks;
- certified checks;
- negotiable Treasury securities, including U.S. Treasury notes or bonds, with conveyance to the Secretary of the Interior of full authority to sell the security in case of default in the performance of the lease's terms and conditions; or
- irrevocable letters of credit that are issued for a specific term by a financial institution whose deposits are federally insured and meet certain conditions and that identify the Secretary of the Interior as sole payee with full authority to demand immediate payment in case of default in the performance of the lease's terms and conditions.

BLM bond reviews. BLM regulations provide flexibility to increase bonds above minimums and require increases above minimum amounts if operators meet certain criteria. Specifically, BLM regulations require BLM to increase the bond amount when an operator who applies for a new drilling permit had previously failed to reclaim a well in a timely manner. For such an operator, BLM must require a bond in an amount equal to its cost estimate for reclaiming the new well if BLM's cost estimate is higher than the regulatory minimum amount. BLM regulations also authorize increases in the bond amount—not to exceed the estimated cost of reclamation and any royalties or penalties owed—whenever the authorized officer determines that the operator poses a risk due to factors such as that the expected reclamation costs exceed the present bond.

In response to our previous recommendation in 2011 that BLM develop a comprehensive strategy to revise its bond adequacy review policy to more clearly define terms and conditions that warrant a bond increase,[21] BLM issued a bond adequacy review policy in July 2013, Instruction

[21]GAO-11-292.

Memorandum 2013-151. The policy contained directives for conducting reviews when bonds meet certain criteria. Specifically, the 2013 bond adequacy review policy called for field offices to, among other things, review each bond at least every 5 years to determine whether the bond value appropriately reflected the level of potential risk posed by the operator. If it did not, authorized officers were to propose an increase (or decrease) in the bond value.

In November 2018, BLM issued a revised bond adequacy review policy, Instruction Memorandum 2019-014, which supersedes the 2013 policy. The 2018 policy continues to call for field offices to review each bond at least every 5 years, but it revised the point system worksheet that field offices are to use when determining whether a bond increase (or decrease) is warranted. Also, in response to our 2018 recommendation that BLM ensure that the reviews of nationwide and statewide bonds reflect the overall risk presented by operators, the 2018 policy calls for additional coordination between BLM headquarters, state offices, and field offices when reviewing nationwide and statewide bonds.

BLM returns or uses bond. If operators reclaim their wells, BLM returns the bond to the operator.[22] Many decades may pass between when BLM collects a bond and when it is returned. If operators do not reclaim their wells, BLM may redeem the certificate of deposit, cash the check, sell the security, or make a demand on the letter of credit to pay the reclamation costs. Liability for reclaiming a well on onshore federal lands can fall to either the lease holder or the operator, and BLM may also hold past owners or operators liable. The liability for past owners or operators extends only to reclamation obligations that accrued before BLM approved the transfer of their lease to a subsequent lessee. They are not liable for reclamation and lease obligations incurred after that transfer is approved.

[22]Bonds are released after final abandonment is approved by BLM, indicating compliance with all lease terms, including reclamation. Statewide or nationwide bonds are not released until final approval of abandonment of all activities under those bonds.

Average Bond Values Per Well Were Slightly Lower in 2018 as Compared to 2008

Based on our review of BLM data, the value of bonds held by BLM for oil and gas operations on a per-well basis were slightly lower in 2018 as compared to 2008. Although the total value of bonds held by BLM for oil and gas operations was higher in 2018 than in 2008 (about $204 million compared to about $188 million, in 2018 dollars), the average bond value per well was slightly lower because the number of wells on federal land was also higher in 2018 than in 2008 (96,199 wells compared to 85,330). Specifically, in 2008, BLM held bonds worth an average of $2,207 per well in 2018 dollars.[23, 24] BLM held bonds worth an average of $2,122 per well in 2018, a decrease of 3.9 percent as compared to 2008 (see table 1).[25]

Table 1: Bureau of Land Management's Oil and Gas Bonds and Wells in 2008 and 2018, in 2018 dollars

	Value of Bonds	Number of Wells	Average Bond Value Per Well
2008	188,316,757	85,330	2,207
2018	204,181,121	96,199	2,122
Percent Change	8.4	12.7	-3.9

Source: GAO analysis of Bureau of Land Management data. | GAO-19-615

Note: The value of bonds in 2008 is as of September 2008. The value of bonds in 2018 is as of May 2018. Data on the number of wells are as of September 2008 and September 2018.

We used BLM data to identify how many wells were covered by each bond and to determine the average bond value per well for each bond

[23]BLM bonds do not typically cover an individual well; however, we calculated the average bond value on a per-well basis (bond amount divided by the number of wells covered by the bond) to compare the value over time adjusted for the increased number of wells. When reporting on all wells, we calculated the average bond value per well as the aggregate value of all BLM bonds divided by the total number of producible well bores. Appendix I provides additional information on our scope and methodology.

[24]GAO-10-245.

[25]Data on the value of bonds in 2008 are as of September 2008. Data on the value of bonds in 2018 are as of May 2018. Data on the number of wells in 2008 are as of September 2008. Data on the number of wells in 2018 are as of September 2018.

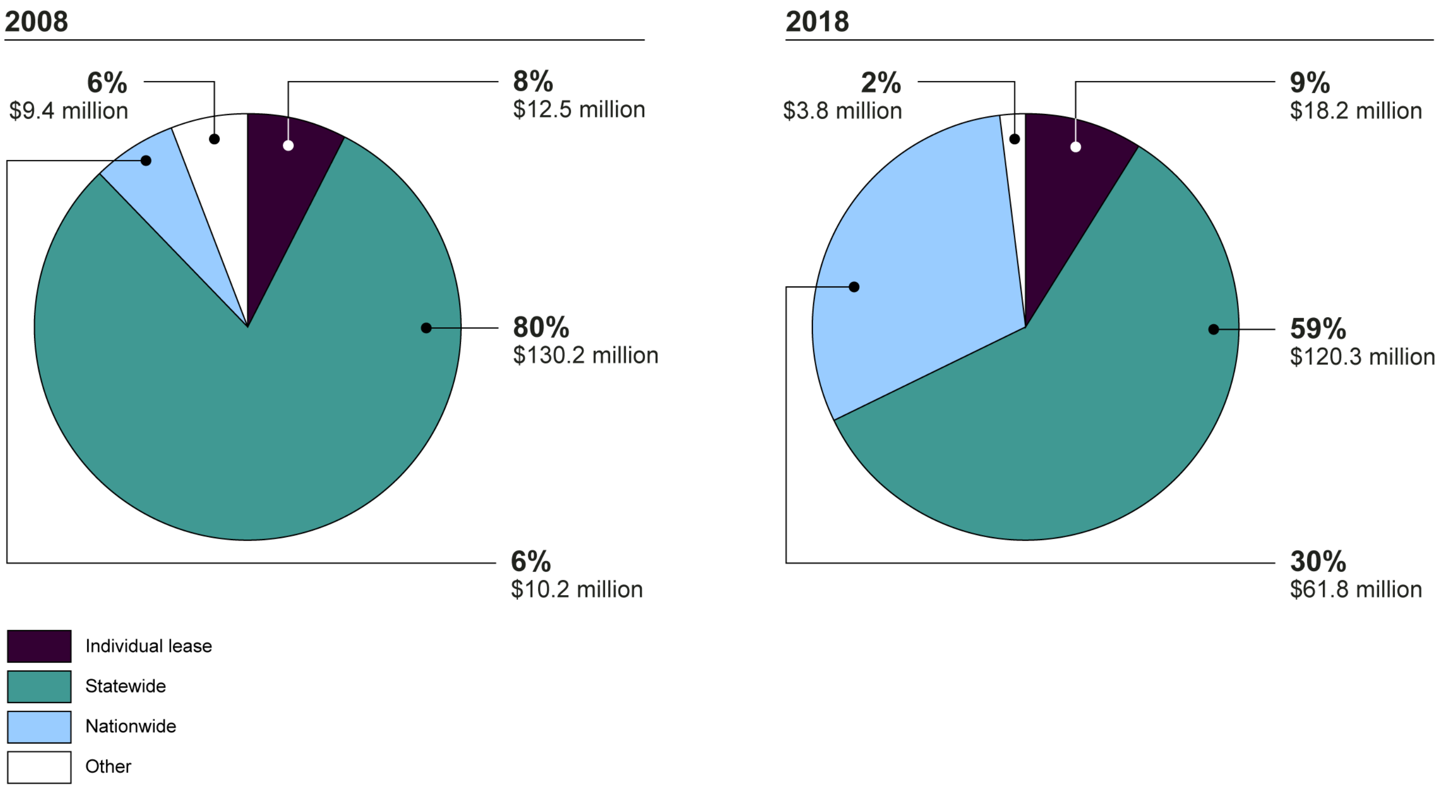
category for bonds that were linked to wells in the data.[26] We found that, on average, as of 2018 an individual lease bond covered about 10 wells, a statewide bond covered about 49 wells, and a nationwide bond covered 374 wells. However, some bonds cover more than the typical number of wells and some fewer. As of 2018, individual lease bonds had the highest average bond value per well at $2,691, and nationwide bonds had the lowest average bond per well value at $890. Statewide bonds had an average bond value per well of $1,592.

The share of the total value of bonds held by BLM that are individual lease, statewide, or nationwide bonds differed in 2018 from 2008 (see Figure 3). The share of individual lease bonds was slightly higher in 2018 as compared to 2008 (about 8 percent in 2008 and about 9 percent in 2018). In 2008, statewide bonds represented about 80 percent (approximately $130 million) of the total value of bonds. In 2018, statewide bonds represented about 59 percent of total bond value (approximately $120 million), but this category still represented the largest share of total bond value. In contrast, nationwide bonds were a lower share of total bond value in 2008 (about 6 percent, approximately $10.2 million) than in 2018 (30 percent, approximately $61.8 million).

[26]To report on the average number of wells per bond by bond category and the average bond value per well by bond category, we analyzed bonds that were linked to wells in BLM's data. Specifically, of 3,357 unique bond numbers in LR2000, 1,547 showed wells were tied to them in AFMSS. These 1,547 bonds covered about 80 percent of the wells in AFMSS. The other 20 percent of wells in AFMSS did not match a bond number in LR2000. These wells may not have listed a bond number, or the bond number listed may not have appeared in LR2000.

Based on this sample, the average bond value per well by bond category is calculated as the aggregate value of BLM bonds in a category divided by the total number of wells covered by bonds of that category. Due to the difference in samples, the total bond value used in the calculations of average bond value per well by bond category differs from the total bond value for all bonds in LR2000. Appendix I provides additional information on our scope and methodology.

Figure 3: Value of Bonds Held by Bureau of Land Management, by Bond Category, in 2008 and 2018



Source: GAO analysis of Bureau of Land Management data. | GAO-19-615

Note: Other category consists of National Petroleum Reserve-Alaska and unit bonds.

BLM officials told us that changes in the composition of the oil and gas industry may have contributed to these changes in the composition of bonds. In particular, officials said some larger companies may have expanded their operations in recent years, sometimes acquiring smaller companies. Large companies with expansive operations are more likely than small companies to have nationwide bonds because such bonds can cover operations in multiple states, which statewide and individual lease bonds do not. Therefore, an industry shift to larger companies would tend to increase the share of nationwide bonds.

Bonds Held by BLM Are Insufficient to Prevent Orphaned Wells

Bonds Do Not Provide Sufficient Financial Assurance to Prevent Orphaned Wells

Bonds do not provide sufficient financial assurance to prevent orphaned wells for several reasons. First, BLM has identified new orphaned wells—wells whose bonds were not sufficient to pay for needed reclamation when operators or other parties failed to reclaim them. As we reported in May 2018, BLM does not track the number of orphaned wells over time and so cannot identify how many wells became orphaned over specific time frames.[27] However, our analyses of BLM's orphaned well lists from different years have shown that BLM has continued to identify new orphaned wells since 2009. We reported in January 2010 that BLM identified 144 orphaned wells in 2009.[28] Then, in May 2018, we reported that BLM identified 219 orphaned wells in July 2017—an increase of 75 orphaned wells.[29] In April 2019, BLM provided a list of 296 orphaned wells that included 89 new wells that were not identified on the July 2017 list.[30]

Bonds are not sufficient to prevent orphaned wells in part because they do not reflect full reclamation costs for the wells they cover. Bonds that are high enough to cover all reclamation costs provide complete financial assurance to prevent orphaned wells because, in the event that an operator does not reclaim its wells, BLM can use the bond to pay for reclamation. On the other hand, bonds that are less than reclamation

[27]See GAO-18-250. We recommended that BLM systematically and comprehensively track orphaned wells. BLM concurred with our recommendation, and officials told us they were exploring making changes to their data systems to improve their ability to track orphaned wells.

[28]GAO-10-245.

[29]GAO-18-250.

[30]BLM headquarters officials told us that some of the wells on the April 2019 list may no longer be orphaned, based on their well status. However, according to officials in one field office, at least some wells in those statuses are still orphaned. As a result, we included all the wells identified in AFMSS as orphaned in our analysis.

costs may not create an incentive for operators to promptly reclaim wells after operations cease because it costs more to reclaim the wells than the operator could collect from its bond. We analyzed bonds that are linked to wells in BLM's data, and found that most of these bonds would not cover reclamation costs for their wells.[31] Specifically, we compared the average bond coverage available for these wells to the two cost scenarios we described above. About 84 percent of these bonds—covering 99.5 percent of these wells—would not fully cover reclamation costs under a low-cost scenario (these bonds have an average value per well of less than $20,000).[32] Less than 1 percent of bonds—covering less than 0.01 percent of these wells—would be sufficient to reclaim all the wells they cover if they were high cost (these bonds have an average value per well of $145,000 or more). The remaining bonds—about 16 percent—have average bond values per well of between $20,000 and less than $145,000.

The majority of bond values do not reflect reclamation costs in large part because most bonds—82 percent—remain at their regulatory minimum

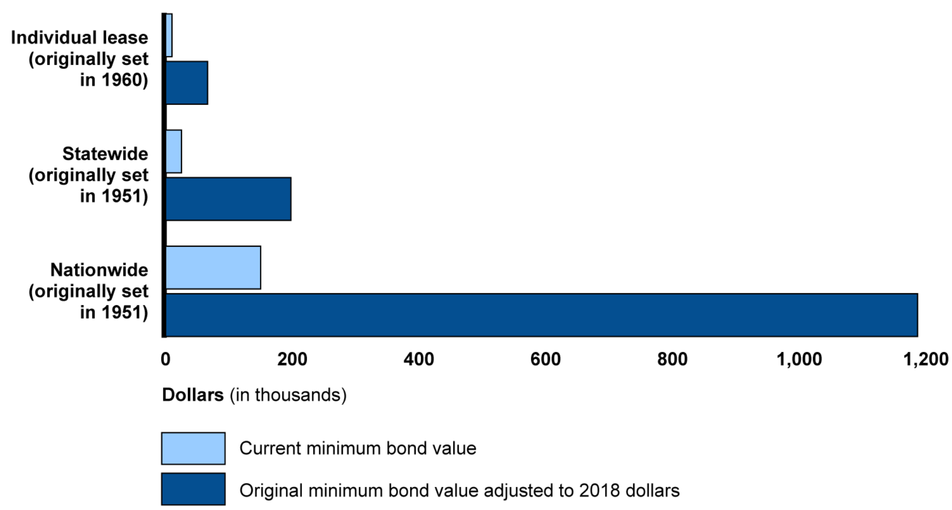
[31]We analyzed bonds that were linked to wells in BLM's data. Specifically, of 3,357 unique bond numbers in LR2000, 1,547 showed wells were tied to them in AFMSS. These 1,547 bonds covered about 80 percent of the wells in AFMSS. The other 20 percent of wells in AFMSS did not match a bond number in LR2000. These wells may not have listed a bond number, or the bond number listed may not have appeared in LR2000. Appendix I provides additional information on our scope and methodology. In our May 2018 report, we found problems with the quality of data in AFMSS, and recommended that the Director of BLM take steps to improve its data quality, for example, by conducting more edit checks and by having data stewards certify the quality of the data. BLM concurred with this recommendation and stated that it would update its policy to provide guidance on standard procedures for data validation review and certification. See GAO-18-250.

[32]We calculated average bond value per well—for each bond—as the bond's value divided by the total number of wells covered the bond, for the sample of wells that were linked to bonds in BLM data. This assessed whether the bond amount is sufficient to cover the reclamation costs associated with all wells covered by the bond. Appendix I provides additional information on our scope and methodology.

values.[33] These regulatory minimums are not reflective of reclamation costs for a number of reasons:

- Regulatory bond minimums have not been adjusted since the 1950s and 1960s to account for inflation. As shown in figure 4, when adjusted to 2018 dollars, the $10,000 individual lease bond minimum would be about $66,000, the $25,000 statewide bond minimum would be about $198,000, and the $150,000 nationwide bond minimum would be about $1,187,000.

Figure 4: Bureau of Land Management Current Regulatory Minimum Oil and Gas Bond Values Compared to Original Minimum Bond Values, Adjusted to 2018 Dollars



Source: GAO analysis of Bureau of Land Management data. | GAO-19-615

- Bond minimums are based on the bond category and do not adjust with the number of wells they cover, which can vary greatly. According to BLM's data, in 2018 the number of wells covered by a single bond

[33] About 14 percent of bonds are above their regulatory minimum values. About 1 percent of bonds are in the other category. About 3 percent of bonds are below their regulatory minimum values. According to BLM officials, bonds below regulatory minimums either (1) do not cover any wells and therefore have no associated liability, or (2) were put in place when regulatory minimums were lower. According to the 2018 BLM bond adequacy review policy, field offices are to review bonds and cannot adjust values to be less than the regulatory minimum values. In 2018, we recommended that BLM strengthen its approach to monitoring field office implementation of bond adequacy review policies, such as collecting and analyzing data on performance indicators and ensuring the quality of the data. Officials told us they are working on revising their guidance on data validation and are implementing quality reviews of their data. See GAO-18-250.

ranged from one well to 6,654 wells. On average, a single bond covered about 68 wells.[34] As wells are added to a bond, the total associated reclamation cost increases even if the bond value does not. A bond that increases with each additional well it covers and then decreases as wells are reclaimed could increase the financial incentive for operators to reclaim their wells in a timely manner. This is because operators would have to contribute additional bond value or would recover some bond value when they add or reclaim a well, respectively. Currently, bond minimums do not automatically adjust in this manner and therefore provide limited financial incentives for an operator to reclaim wells in a timely manner.

- Bond minimums do not reflect characteristics of individual wells such as depth or location, but such characteristics can affect reclamation costs, according to BLM officials. Wells are being drilled deeper than in the past; in 1950, well depth averaged about 3,700 feet, and in 2008, it averaged about 6,000 feet. Newer wells may be drilled 10,000 feet vertically. Officials from one BLM field office told us they assume a cost of $10 per foot of well depth to plug a well, so as wells are drilled deeper, plugging costs typically increase proportionally. Additionally, the location of some wells makes them more expensive to reclaim. For example, BLM officials told us about several wells that may cost three times more to reclaim than other nearby wells because they are located in the middle of a river, making them hard to reach.

In addition to BLM having identified orphaned wells over the last decade, we identified inactive wells at increased risk of becoming orphaned and found their bonds are often not sufficient to reclaim the wells. Our analysis of BLM bond value data and Office of Natural Resources Revenue production data showed a significant number of inactive wells remain unplugged and could be at increased risk of becoming orphaned. Specifically, we identified 2,294 wells that may be at increased risk of becoming orphaned because they have not produced since June 2008 and have not been reclaimed.[35] Further, for a majority of these at-risk wells, their bonds are too low to cover typical reclamation costs for just these at-risk wells. Our analysis of oil and gas production data showed

[34]The number of wells covered by a single bond was calculated using wells that are linked to bonds in BLM's data.

[35]Our analysis used conservative assumptions to estimate a lower bound of the number of wells at the end of their useful life that have not been reclaimed. In particular, our lower-bound estimate does not include some coalbed methane wells that have been inactive for less than 9 years but are unlikely to produce at current prices because of the relatively higher cost of coalbed methane production. Appendix I provides additional information on our scope and methodology.

these wells have not produced oil or gas or been used in other ways, such as serving as injection wells, since at least June 2008, when oil and gas prices were at or near record highs.[36] Given that the Energy Information Administration projects oil and natural gas prices will remain at levels significantly below the 2008 highs through 2050, it is unlikely price will motivate operators to reopen these wells. Some of these wells have been inactive for far longer.[37] Since these at-risk wells are unlikely to produce again, an operator bankruptcy could lead to orphaned wells unless bonds are adequate to reclaim them. If the number of at-risk wells is multiplied by our low-cost reclamation scenario of $20,000, it implies a cost of about $46 million to reclaim these wells. If the number of these wells is multiplied by our high-cost reclamation scenario of $145,000, it implies a cost of about $333 million.[38] When we further analyzed the available bonds for these at-risk wells, we found that most of these wells (about 77 percent) had bonds that would be too low to fully reclaim the at-risk wells under our low-cost scenario.[39] More than 97 percent of these at-risk wells have bonds that would not fully reclaim the wells under our high-cost scenario.

BLM has a policy for reviewing the adequacy of bonds but has not been able to consistently secure bond increases when needed, and this policy

[36]According to the Energy Information Administration, the weekly spot price for West Texas Intermediate oil at Cushing, Oklahoma, was $142.52 per barrel the first week of July 2008. As of the first week of May 2019, the price was $62.90 per barrel. Similarly, the Energy Information Administration reported that the Henry Hub weekly spot price for natural gas was $13.20 per million British thermal units the first week of July 2008. It was $2.59 per million British thermal units the first week of May 2019.

[37]We reported in May 2018 on over 1,000 wells that had been inactive for 25 years or more. That number includes some wells on Indian land, which are not included in the scope of this report. GAO-18-250.

[38]Not all of these wells may become orphaned, although they are at an increased risk of becoming orphaned as compared to active wells or wells that have been inactive for fewer years.

[39]We analyzed bonds linked to at-risk wells in BLM's data. Of the 2,294 at-risk wells, 2,041 were linked to bonds in BLM's data (about 89 percent) and these formed the basis of our analysis of bond value per at-risk well; the remaining wells were not tied to any bonds in LR2000. In addition, we examined costs associated with at-risk wells covered by these bonds and did not count any other wells covered by the bond if they were not at risk. Appendix I provides additional information on our scope and methodology.

has not resulted in bonds that would be adequate to reclaim most wells.[40] BLM's bond adequacy review policy calls for field office staff to review oil and gas bonds at least every 5 years to determine whether the bond amount appropriately reflects the level of potential risk posed by the operator. However, according to BLM documentation, its offices did not secure about 84 percent of the proposed bond increases in fiscal years 2016 and 2017. BLM officials at one field office and one state office noted it is difficult to secure increases from bond reviews when firms are already in difficult financial situations. In November 2018, BLM updated its bond adequacy review policy and called for the agency to focus on securing bond increases from operators that show the highest risk factors. BLM's updated policy more explicitly lays out steps to secure bond increases, including that BLM should not approve new applications to drill from an operator while waiting for a bond increase. The new policy also gives BLM officials discretion to not pursue a bond increase after considering other priorities demanding staff time and workload. It is unclear whether the update will improve BLM's ability to secure bond increases, as it may not address the underlying challenge of attempting to increase bonds from operators who are already in a difficult financial position.

While BLM's federal oil and gas bond minimums do not sufficiently reflect the costs of well reclamation, requirements for bond amounts for other federal mining and energy development activities account for potential reclamation costs to some extent. For example, for bonds for surface coal mining and hardrock mining on federal lands, the Department of the Interior requires bond amounts based on the full estimated cost of reclamation.[41] For grants of federal rights-of-way for wind and solar energy development in designated leasing areas, BLM requires bonds based on a minimum amount per wind turbine or per acre of solar. For such grants in all other areas, the bonds are based on the estimated cost of reclamation but cannot be less than the per-turbine or per-acre amounts previously mentioned.

[40]BLM's bond adequacy reviews use a points-based system to examine aspects of an operator's well status (such as its number of wells idle for at least 7 years), compliance history (such as its number of incidents of drilling without approval), and reclamation stewardship (such as its number of reclamation related incidents of noncompliance issued in the last 5 years).

[41]GAO, *Financial Assurances for Reclamation: Federal Regulations and Policies for Selected Mining and Energy Development Activities*, GAO-17-207R (Washington, D.C.: Dec. 16, 2016).

Additionally, some states have minimum bond requirements for oil and gas wells on lands in the state that, unlike federal bond minimums, adjust with the number of wells they cover or the characteristics of the wells, or both. For example, Texas and Louisiana offer operators with wells on lands in those states the choice of a bond based on total well depth or based on the number of wells. Specifically, the Texas Railroad Commission lets operators choose bonds based on either the total depth of all wells on lands in the state multiplied by $2 per foot, or minimums based on the number of wells covered. If operators choose the latter, the bond for 0 to 10 wells is $25,000; the bond for 11 to 99 wells is $50,000; and the bond for 100 or more wells is $250,000. In Louisiana, the Office of Conservation offers operators with wells on lands in the state the choice of a bond based on total well depth or based on the number of wells. Louisiana further specifies a multiplier that varies depending on the total depth of the well. For example, the bond calculation is $2 per foot for wells less than 3,000 feet deep, $5 per foot for wells from 3,001 to 10,000 feet deep, and $4 per foot for wells 10,001 feet deep or deeper. Operators in Louisiana can alternatively choose to follow a system based on number of wells, with a minimum bond for 10 or fewer wells set at $50,000, a minimum bond for 11 to 99 wells set at $250,000, and a minimum bond for 100 or more wells set at $500,000. Pennsylvania's Department of Environmental Protection requires bonds for unconventional wells that vary based on the number of wells and well bore length.[42]

The Mineral Leasing Act of 1920, as amended, requires federal regulations to ensure that an adequate bond is established before operators begin surface-disturbing activities on any lease, to ensure complete and timely reclamation of the lease tract as well as land and surface waters adversely affected by lease operations. The Mineral Leasing Act of 1920 does not require that BLM set bonds at full reclamation costs. However, the gap between expected reclamation costs and minimum bond amounts has grown over time because the minimums have not been adjusted since they were established in the 1950s and 1960s, whereas reclamation costs have increased due to inflation and the changing characteristics of wells being drilled. In the absence of bond

[42]Pennsylvania defines conventional wells as those that produce oil or gas from a conventional formation. It defines an unconventional well as a gas well that is drilled into an unconventional formation, which is defined as a geologic shale formation below the base of the Elk Sandstone or its geologic equivalent where natural gas generally cannot be produced economically except by horizontal or vertical well bores stimulated by hydraulic fracturing or other techniques to expose more of the formation to the well bore.

levels that more closely reflect expected reclamation costs, such as by increasing regulatory minimums and incorporating consideration of the number of wells on each bond and their characteristics, BLM will continue to face risks that its bonds will not provide sufficient financial assurance to prevent orphaned wells. In particular, adjusting bond minimums so that bonds more closely reflect expected reclamation costs up front could help decrease the need for bond increases later when companies are potentially in financial distress.

BLM Does Not Currently Assess User Fees to Fund Orphaned Well Reclamation

In addition to fulfilling its responsibility to prevent new orphaned wells, it falls to BLM to reclaim wells that are currently orphaned, and BLM has encountered challenges in doing so. We reported in May 2018 that 13 BLM field offices identified about $46.2 million in estimated potential reclamation costs associated with orphaned wells and with inactive wells that officials deemed to be at risk of becoming orphaned. There is also a risk more wells will become orphaned in coming years, as we described above. Based on the most recent orphaned well lists we received from BLM, 51 wells that BLM identified in 2009 as orphaned had not been reclaimed as of April 2019.

The Energy Policy Act of 2005 (EPAct 2005) directs Interior to establish a program that, among other things, provides for the identification and recovery of reclamation costs from persons or other entities currently providing a bond or other financial assurance for an oil or gas well that is orphaned, abandoned, or idled.[43] One way in which BLM may be able to accomplish this is through the imposition of user fees.[44] In 2008, we found that well-designed user fees can reduce the burden on taxpayers to finance those portions of activities that provide benefits to identifiable

[43]The Secretary of the Interior is to establish this program in cooperation with the Secretary of Agriculture.

[44]Generally, under the miscellaneous receipts statute, money an agency receives for the government from a source outside of the agency must be deposited into the Treasury. 31 U.S.C. § 3302. However, BLM "may establish reasonable filing and service fees and reasonable charges, and commissions with respect to applications and other documents relating to the public lands and may change and abolish such fees, charges, and commissions." 43 U.S.C. § 1734(a). All such fees "for processing, recording, or documenting authorizations to use . . . public land natural resources (including . . . mineral) and for providing specific services to public land users, and which are not presently being covered into any [BLM] appropriation accounts, and not otherwise dedicated by law for a specific distribution, shall be made immediately available for program operations in this account and remain available until expended." *Id*. § 1734a.

users.[45] Further, according to Office of Management and Budget guidance, it may be appropriate for an agency to request authority to retain the fee revenue if the user fees offset the expenses of a service that is intended to be self-sustaining.[46]

The volume of drilling applications and inactive wells provide an opportunity to fund reclamation costs. According to BLM data, the agency processes more than 3,500 applications to drill each year, on average, and has over 14,000 inactive wells. Based on our calculations, a separate fee of about $1,300 charged at the time a drilling application is submitted (in addition to the current drilling application filing fee, which is $10,050), or an annual fee of less than $350 for inactive wells could generate enough revenue to cover, in a little over a decade, the entire $46 million potential reclamation costs field offices identified to us.[47] In commenting on a draft of this report, BLM stated that it does not have the authority to seek or collect fees from lease operators to reclaim orphaned wells. Developing a mechanism to obtain funds from operators to cover the costs of reclamation, consistent with EPAct 2005, could help ensure that BLM can completely and timely reclaim wells without using taxpayer dollars.

Other federal programs, including other BLM programs, collect fees from users to fund reclamation activities. For example, the federal government collects fees from mining companies to reclaim abandoned mines. Specifically, the federal abandoned mine reclamation program is funded in part by fees on coal production. We reported in March 2018 that the

[45]In May 2008, we issued a user fee design guide that examined how the four key design and implementation characteristics—how fees are set, collected, used, and reviewed—may affect the economic efficiency, equity, revenue adequacy, and administrative burden of the fees. GAO, *Federal User Fees: A Design Guide*, GAO-08-386SP (Washington, D.C.: May 2008).

[46]According to Office of Management and Budget Circular A-25, every 2 years, agencies should review programs that are not currently funded by user fees to determine whether fees should in fact be assessed for government services. Once user fees are implemented, revenue from the fees will be credited to the general fund of the U.S. Treasury as miscellaneous receipts unless otherwise specified by law. (See: Office of Management and Budget, Circular No. A-25 Revised, Memorandum for Heads of Executive Departments and Establishments (July 8, 1993).

[47]To arrive at these example fees, we divided the $46 million in potential reclamation costs by 10 and divided the result by the number of drilling permits and inactive wells, respectively, in 2018.

program had spent about $3.9 billion to reclaim abandoned mine lands since the program's creation in 1977.[48]

Additionally, some states with oil and gas development have dedicated funds for reclaiming orphaned wells. In Wyoming, the state's Oil and Gas Conservation Commission's Orphan Well Program reclaims orphaned wells on state or private lands for which bonds and operator liability are unavailable or insufficient to fund reclamation. The program is funded through a conservation tax assessed on the sale of oil and natural gas produced in Wyoming. Through this program, the Wyoming Oil and Gas Conservation Commission has reclaimed approximately 2,215 wells since 2014, according to a Commission official. Similarly, in Arkansas, operators make annual payments to its abandoned well plugging fund based on the number of wells and permits they have, on a sliding scale. For example, at the low end, operators with one to five wells or permits pay $100 per well, and at the high end, operators with over 300 wells or permits pay $4,000 per operator.[49] The Arkansas fund was used to reclaim 136 wells in fiscal years 2016 through 2018, according to an official with the state's Oil and Gas Commission. Virginia's Orphaned Well Fund is funded through a $200 surcharge on each permit application. The fund is administered by the Virginia Division of Gas and Oil, which prioritizes wells to reclaim according to their condition and potential threat to public safety and the environment.

Conclusions

BLM oversees private entities operating thousands of oil and gas wells on leased federal lands and has taken steps over the years to strengthen its management of the potential liability that oil and gas operations represent should operators not fully reclaim wells and return lands to their original condition when production ceases. For example, the agency's 2013 bond adequacy review policy outlined how bonds were to be reviewed every 5 years and bond amounts adjusted depending on risks presented by operators. However, we found average bond values were slightly lower in 2018 as compared to 2008 and BLM has not obtained bond increases for the majority of instances in which its reviews identify that increases are

[48]GAO, *Coal Mine Reclamation: Federal and State Agencies Face Challenges in Managing Billions in Financial Assurances*, GAO-18-305 (Washington, D.C.: Mar. 6, 2018).

[49]According to an Arkansas Oil and Gas Commission official, the state also makes transfers from other agency sources and deposits forfeited bonds into the abandoned well plugging fund.

needed. Instead, most bonds are at their regulatory minimum values, which are not sufficient to cover reclamation costs incurred by BLM. Without adjusting bond levels to more closely reflect expected reclamation costs—such as by considering the effects of inflation, the number of wells covered by a single bond, and the characteristics of those wells—BLM faces ongoing risks that not all wells will be completely and timely reclaimed, resulting in additional orphaned wells.

Further, BLM faces a backlog of orphaned wells to reclaim—with 51 dating back at least 10 years. Unlike some other federal and state programs that obtain funds from industry through fees or dedicated funds, BLM does not do so for reclaiming orphaned wells. According to BLM, it does not have the authority to seek or collect fees from lease operators to reclaim orphaned wells. Authorizing and requiring the implementation of a mechanism to obtain funds from oil and gas operators to cover the costs of reclamation could help ensure BLM can completely and timely reclaim wells.

Matter for Congressional Consideration

Congress should consider giving BLM the authority to obtain funds from operators to reclaim orphaned wells, and requiring BLM to implement a mechanism to obtain sufficient funds from operators for reclaiming orphaned wells. (Matter for Consideration 1)

Recommendation for Executive Action

The Director of BLM should take steps to adjust bond levels to more closely reflect expected reclamation costs, such as by increasing regulatory minimums to reflect inflation and incorporating consideration of the number of wells on each bond and their characteristics. (Recommendation 1)

Agency Comments and Our Evaluation

We provided a draft of this product to BLM for comment. In its written comments, reproduced in appendix II, BLM concurred with the recommendation. BLM stated that it is committed to ensuring that its field offices continue to review oil and gas bonds at least every 5 years, or earlier when warranted, and noted its November 2018 Instruction Memorandum 2019-014 updated its bond review policy. BLM further stated that, while the adjustment of bond values may not reflect the inflation index, the policy is intended to increase bond amounts while fostering an environment conducive to BLM's leasing operations. As we point out in this report, BLM has historically had difficulties securing bond increases through bond reviews, and so additional steps may be needed to adjust bond levels to more closely reflect expected reclamation costs.

In the draft we provided to BLM for comment, we included a recommendation that the Director of BLM should take steps to obtain funds from operators for reclaiming orphaned wells. BLM did not concur with this recommendation, saying it does not have the authority to seek or collect fees from lease operators to reclaim orphaned wells. We continue to believe a mechanism for BLM to obtain funds from oil and gas operators to cover the costs of reclamation for orphaned wells could help ensure BLM can completely and timely reclaim these wells, some of which have been orphaned for at least 10 years. We have therefore instead made a matter for Congressional consideration.

BLM also provided technical comments, which we incorporated as appropriate.

We are sending copies of this report to the appropriate congressional committees, the Secretary of the Interior, and other interested parties. In addition, the report is available at no charge on the GAO website at http://www.gao.gov.

If you or your staff have any questions about this report, please contact me at (202) 512-3841 or ruscof@gao.gov. Contact points for our Offices of Congressional Relations and Public Affairs may be found on the last page of this report. GAO staff who made key contributions to this report are listed in appendix III.

Frank Rusco
Director,
Natural Resources and Environment

Appendix I: Objectives, Scope, and Methodology

This report (1) describes the value of bonds for oil and gas wells in 2018 compared to 2008, and (2) examines the extent to which the Bureau of Land Management's (BLM) bonds ensure complete and timely reclamation and thus prevent orphaned wells.

To describe the value of bonds for oil and gas wells in 2018 compared to 2008, we analyzed oil and gas well data from BLM's Automated Fluid Minerals Support System (AFMSS) as of May 2018 and data from BLM's Legacy Rehost 2000 (LR2000) system on bonds as of May 2018. Bond data we reviewed included the bond category (e.g., individual lease or nationwide) and bond value. We compared these data to data obtained from the same systems for 2008 and reported by GAO in 2010.[1] We matched the May 2018 data from the two systems based on the bond number—a variable in both systems—to identify how many wells were covered by each bond and to determine the average bond value per well for each bond category. To assess the reliability of AFMSS and LR2000 data elements, we reviewed agency documents, met with relevant agency officials, and performed electronic testing. We found these data to be sufficiently reliable for our purposes. We also interviewed BLM headquarters officials to understand why bond composition may have changed over time. To report on the number of bonded wells held by BLM, we used a published BLM value for producible well bores—wells capable of production—which should represent a lower bound on the number of bonded wells in September 2018 because some wells may be plugged or temporarily incapable of production but would still require a bond if the surrounding site had not been fully reclaimed. To determine the average value of bonds per well in 2018, we divided the total value of all bonds held by BLM by the total number of producible well bores.

To examine the extent to which BLM's bonds ensure complete and timely reclamation and prevent orphaned wells, we conducted the following analyses:

- Reclamation cost scenarios: To determine whether bonds are sufficient to cover potential reclamation costs for the wells they cover, we identified typical high- and low-cost scenarios for well reclamation (including plugging the well and reclaiming the surrounding well site) and compared those scenarios to the average bond value available per well. To determine high- and low-cost reclamation scenarios, we

[1]GAO, *Oil and Gas Bonds: Bonding Requirements and BLM Expenditures to Reclaim Orphaned Wells*, GAO-10-245 (Washington, D.C.: Jan. 27, 2010).

analyzed BLM's well reclamation cost estimates on proofs of claim submitted to the Department of Justice from calendar year 2016 through May 2018.[2] These 59 proofs of claim listed estimated reclamation costs for 8,664 well sites. We calculated the average reclamation cost per well for each individual proof of claim by dividing the total dollar value claimed for reclamation liability (actual liability plus potential liability) by the total number of wells listed in each proof of claim document. We found the average reclamation cost estimates for each proof of claim have a bimodal distribution, meaning that data are clustered around two distinct cost levels, rather than clustered around a single average cost. As a result, we determined that using two separate measures that indicate typical values for separate groups of low-cost and high-cost wells would provide more meaningful statistics about cost. We therefore selected reclamation costs of $20,000 for the low-cost reclamation scenario and $145,000 for the high-cost scenario based on the 25th and 75th percentiles of the distribution of average estimated reclamation cost per proof of claim, weighted by the number of wells on each proof of claim.

- Bond value per well: To determine the average bond value available per well, we analyzed bonds listed in LR2000 that were tied to wells listed in AFMSS using the bond number—a variable in both systems. We found that 1,547 out of the 3,357 unique bond numbers in LR2000 had wells tied to them in AFMSS. These 1,547 bonds covered about 80 percent of the wells in AFMSS.[3] The other 20 percent of wells in AFMSS either did not list a bond number, or the bond number listed was not in LR2000. For each bond in LR2000 covering wells in AFMSS, we calculated the bond available per well as the bond value divided by the number of wells it covers. We then compared the bond values per well against both high ($145,000 per well) and low ($20,000 per well) reclamation cost scenarios to identify which bonds would be adequate to reclaim all the wells they covered under different cost scenarios. If AFMSS bond information was incomplete, it is possible that there are more wells covered by bonds than we were able to identify—and therefore the bond value per well would be lower than we found.

[2]These estimates come from proofs of claim that BLM submits when an operator files for bankruptcy.

[3]In this report we refer to the wells that the bonds were tied to as the wells the bonds covered.

- At-risk wells: To identify wells that may be at greater risk of becoming orphaned and determine whether their bonds are sufficient to cover potential reclamation costs, we used well production data from the Office of Natural Resources Revenue's Oil and Gas Operations Report (OGOR) as of June 2017 and bond values from LR2000. First, we defined wells as "at risk of becoming orphaned" if they met several criteria. Specifically, we identified wells that (1) had recent OGOR reports (on or after March 2017); (2) had not been used productively from at least June 2008 through the most recent record (meaning the well did not report producing any volume of oil or gas during this timeframe, nor were any volume of water or materials injected into the well during this timeframe); (3) were not being used as a monitoring well in the most recent record, which we considered a productive use; and (4) had not been plugged and abandoned. We selected June 2008 as the cutoff date for productivity because in June and July of 2008, oil and gas prices hit peaks that have not since been reached again, and which the Energy Information Administration does not expect prices to reach again through at least 2050.[4] We believe our analysis is a conservative estimate of wells at greater risk, in part because we did not include wells that produced when prices were at their peaks and stopped producing soon afterward and may be unlikely to produce in the future unless prices reach the same peaks again. In addition, our lower-bound estimate does not include some coalbed methane wells that have been inactive for less than 9 years but are unlikely to produce at current prices because of the relatively higher cost of coalbed methane production. We also excluded wells that reported any volume of oil or gas production or water injection since June 2008, although some very low-producing wells may also be at risk of becoming orphaned.
- Bond value for at-risk wells: To calculate the average bond value per at-risk well, we identified bonds listed in LR2000 that were tied to at-risk wells in AFMSS to determine the value of bonds available to reclaim these at-risk wells if needed. We identified 2,041 of the 2,294 at-risk wells were linked to bonds. For each bond, we divided the bond value by the number of at-risk wells it covered to determine the bond amount per at-risk well. In cases in which an at-risk well was linked to more than one bond, we additionally calculated the average

[4]According to the Energy Information Administration, the weekly spot price for West Texas Intermediate oil at Cushing, OK was $142.52 per barrel the first week of July 2008. As of the first week of May 2019 the price was $62.90 per barrel. Similarly, Energy Information Administration reported the Henry Hub weekly spot price for natural gas was $13.20 per million British thermal units the first week of July 2008. It was $2.59 per million British thermal units the first week of May 2019.

of the bond value per at-risk well for each bond linked to the well. To determine the sufficiency of bonds for at-risk wells, we identified the number of wells with an average bond value per at-risk well equal to or greater than $20,000 (low cost reclamation scenario) or $145,000 (high cost reclamation scenario).

- Orphaned wells: We compared three lists of orphaned wells based on data provided by BLM in 2009, July 2017, and April 2019. The 2009 data are from our January 2010 report, which used Orphaned Well Scoring Checklists that list information such as the well's name and location.[5] The July 2017 data are from our May 2018 report, which used an orphaned well list generated through a query of AFMSS by BLM.[6] The April 2019 list was generated through a query of an updated version of AFMSS known as AFMSS 2.[7] We compared the lists to identify how many wells that were on the 2009 list remained on the 2019 list, and how many wells that were on the 2017 list were on the 2019 list.

To assess the reliability of the AFMSS, LR2000, and OGOR data elements we used, we reviewed agency documents, met with relevant agency officials, and performed electronic testing. We found these data elements to be sufficiently reliable for our purposes. Similarly, to assess the reliability of the 2019 orphaned well list, we reviewed agency documents and met with relevant agency officials. Though we identified shortcomings with data on orphaned wells, we nevertheless found these data to be sufficiently reliable for the purpose of describing the orphaned wells BLM has identified. To assess the reasonableness of proofs of claim data, we interviewed relevant agency officials and reviewed agency documents.

To understand how BLM manages bonds, we reviewed BLM's policies and interviewed officials from four BLM state offices and four BLM field offices. We selected these state and field offices because, according to AFMSS data, they were responsible for managing the largest numbers of wells on federal land. These BLM state offices were California, New

[5]GAO-10-245

[6]GAO, *Oil and Gas Wells: Bureau of Land Management Needs to Improve Its Data and Oversight of Its Potential Liabilities*, GAO-18-250 (Washington, D.C.: May 16, 2018).

[7]BLM headquarters officials told us that some of the wells on the list may no longer be orphaned, based on their well status. However, according to officials in one field office, at least some wells in those statuses are still orphaned. As a result, we included all the wells identified in AFMSS as orphaned in our analysis.

Mexico, Utah, and Wyoming. These BLM field offices were Bakersfield, Buffalo, Carlsbad, and Farmington. We also interviewed officials from BLM's headquarters office in Washington, D.C. Findings from the selected BLM offices cannot be generalized to officials we did not interview but provide a range of views. To understand how some states with oil and gas development on state lands set minimum bonds and fund orphaned well reclamation, we contacted officials from oil and gas oversight agencies in Arkansas, Louisiana, Pennsylvania, Texas, Virginia, and Wyoming.[8]

We conducted this performance audit from January 2018 to September 2019 in accordance with generally accepted government auditing standards. Those standards require that we plan and perform the audit to obtain sufficient, appropriate evidence to provide a reasonable basis for our findings and conclusions based on our audit objectives. We believe that the evidence obtained provides a reasonable basis for our findings and conclusions based on our audit objectives.

[8]The state agencies we contacted are the Arkansas Oil and Gas Commission; the Louisiana Office of Conservation; the Pennsylvania Department of Environmental Protection; the Texas Railroad Commission; the Virginia Department of Mines, Minerals, and Energy; and the Wyoming Oil and Gas Conservation Commission.

Appendix II: Comments from the Department of the Interior

United States Department of the Interior
BUREAU OF LAND MANAGEMENT
Washington, D.C. 20240
http://www.blm.gov

AUG 3 0 2019

Mr. Frank Rusco
Director, Natural Resources and Environment
U.S. Government Accountability Office
441 G Street, NW
Washington, DC 20548

Dear Mr. Rusco:

Thank you for providing the Department of the Interior (Department) the opportunity to review and comment on the draft Government Accountability Office (GAO) report entitled, *Oil and Gas: Bureau of Land Management Should Address Risks from Insufficient Bonds to Reclaim Wells* (GAO-19-615). We appreciate GAO's review of the bonds that operators, operating rights owners, or lessees submit to BLM to ensure compliance with the Mineral Leasing Act (30 U.S.C. §§ 181 *et seq.*), including complete and timely plugging of the oil and gas wells and reclamation of the lease(s).

The GAO issued BLM two recommendations to address its findings. Below is BLM's response to GAO's recommendations.

Recommendation 1: The Director of BLM should take steps to adjust bond levels to more closely reflect expected reclamation costs, such as by increasing regulatory minimums to reflect inflation and incorporating consideration for the number of wells on each bond and their characteristics.

Response: Concur. The BLM recently updated its bonding program policy by issuing Instruction Memorandum 2019-014. The BLM is committed to ensuring that its field offices continue to review oil and gas bonds at least every five years, or earlier when warranted. The updated policy requires BLM to review oil and gas bonds to determine whether the bond amount appropriately reflects the level of potential risk(s) (liability) posed by the operators along with their positive compliance history. While the adjustment of bond levels may not reflect the inflation index, it is intended to increase bond amounts while fostering an environment conducive to BLM's leasing operations.

Recommendation 2: The Director of BLM should take steps to develop a mechanism to obtain funds from operators for reclaiming orphaned wells and if needed, request additional authority from Congress for such a mechanism.

Response: Do Not Concur. The BLM does not have the authority to seek or collect fees from lease operators to reclaim orphaned wells. To the extent Congress decides to authorize this activity as in Section 349 of the Energy Policy Act of 2005, it is within Congress' purview.

The enclosure contains comments for your consideration when finalizing the report.

If you have any questions about this response, please contact Corey Grant, Acting Chief, Division for Evaluations and Management Services, at (202) 912-7040 or LaVanna Stevenson, Audit Liaison Officer, at (202) 912-7077.

Sincerely,

Joseph R. Balash
Assistant Secretary
Land and Minerals Management

Enclosure

Appendix III: GAO Contact and Staff Acknowledgments

GAO Contact

Frank Rusco at (202) 512-3841 or ruscof@gao.gov

Staff Acknowledgments

In addition to the contact named above, Quindi Franco (Assistant Director), Marietta Mayfield Revesz (Analyst-in-Charge), Marie Bancroft, William Gerard, Cindy Gilbert, Gwen Kirby, Joe Maher, Shaundra Patterson, Dan Royer, and Jerry Sandau made key contributions to this report.

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RON GALPERIN
CONTROLLER

June 27, 2018

Honorable Eric Garcetti, Mayor
Honorable Michael Feuer, City Attorney
Honorable Members of the Los Angeles City Council

Re: Review of the City of Los Angeles' Oil and Gas Drilling Sites

The history of Los Angeles is linked to the discovery and rise of oil and gas drilling. As of April 2018, there were about 5,000 known wells within City borders - about one-fifth of which are active or idle. With so many active and idle wells, it is essential that we do everything possible (1) to protect the health and safety of Angelenos, (2) to collect associated revenues to which our City and its residents are entitled, and (3) to increase transparency and accountability.

Background: The discovery of oil near present-day Dodger Stadium at the end of the 19th century played a critical role in Los Angeles' development. By 1930, the City's population grew to 1.2 million as California produced one quarter of the world's oil output. The history of this oil boom still dot the City's landscape - with active, idle, buried and abandoned oil and gas wells located near homes, schools, parks, hospitals and workplaces.

Numbers: According to the California Department of Conservation, Division of Oil, Gas, and Geothermal Resources (DOGGR) database, as of April 2018, there are 5,130 oil and gas wells within the City of Los Angeles. DOGGR, the state agency that oversees the drilling, operation, maintenance, and plugging and abandonment of oil, natural gas, and geothermal wells, indicates 3,133 of these are plugged and abandoned (wells that have been sealed with cement), 930 are buried, 780 are active and 287 idle (wells that have been inactive for a 24 consecutive months). About 77% of active and idle wells in the City are operated by six companies. A map illustrating oil and gas wells within the City of Los Angeles can be found at www.lacontroller.org/oilandgasreview.

(1) Protecting Angelenos: The City needs to take a more proactive, inclusive approach to oil and gas well inspections. The Los Angeles Fire Department has an inspection and permitting framework to protect residents and property from hazards of fire or explosions.

These inspections - conducted based on geographic data and date of last inspections - present an opportunity to assess risk and mitigate disaster. To improve information sharing, the City should refine its inspection program to enhance interdepartmental collaboration while also implementing a risk-based approach to site selection.

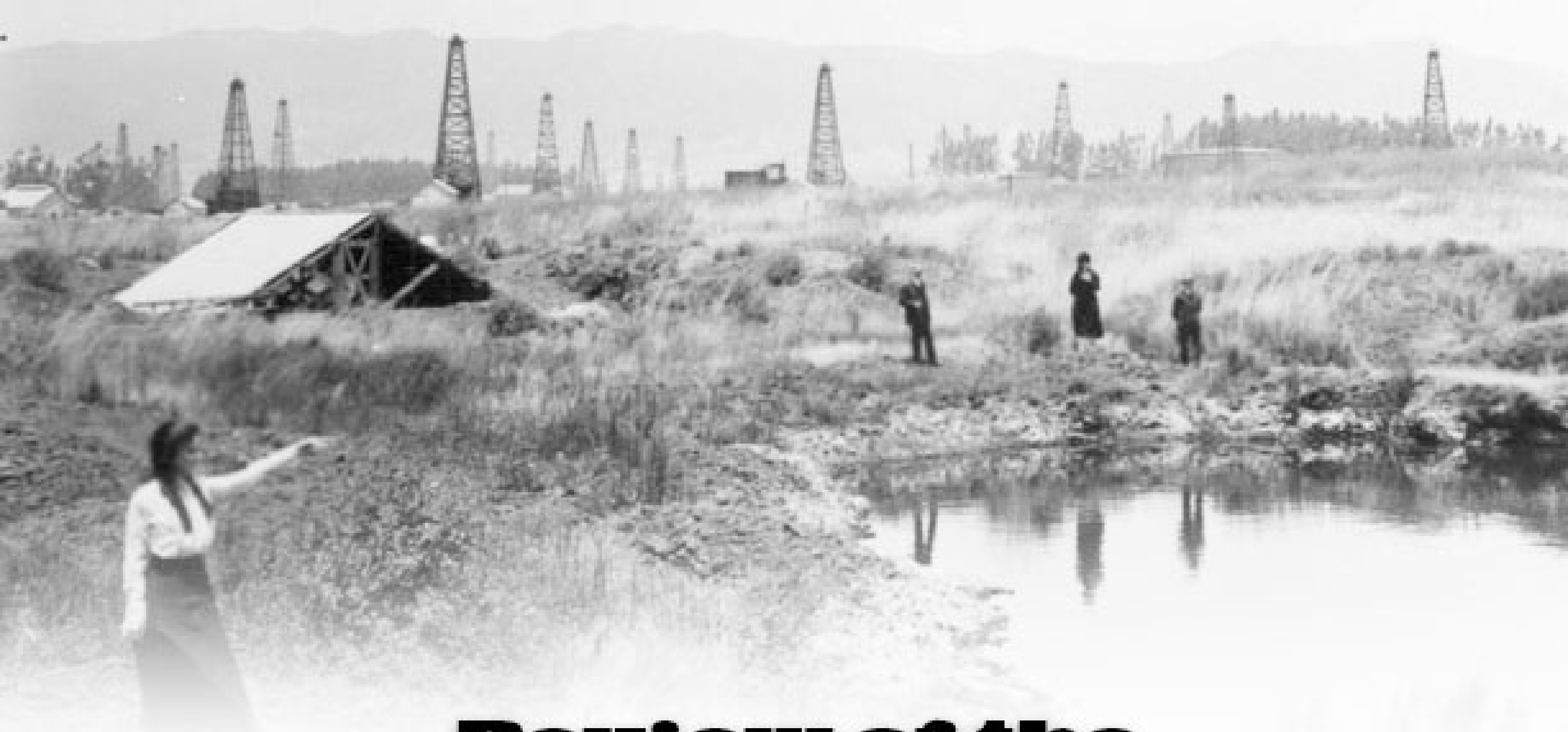
(2) **Protecting taxpayer's financial interest**: The City does not have adequate insurance and bond requirements to protect taxpayers from well operators that knowingly or unknowingly cause harm to the public or environment. There is more the City can and should do to control liabilities, to recover costs, and to consider other revenue generating measures. The City should consider policy changes to require that all well operators obtain, maintain and show proof of a combination of adequate insurance coverage and surety bonds while also performing periodic reviews of bonds/insurance policies. The City should also file claims when irresponsible operators of drilling sites demonstrate noncompliance with legal requirements and conditions of approval.

(3) **Increasing transparency:** Because it lacks comprehensive and reliable information about oil and gas drilling sites, the City cannot effectively facilitate coordination between Departments or make timely, data-driven policy decisions. In addition to building a centralized repository of interagency and interdepartmental information, officials should consider policy changes that require operators of oil and gas drilling sites to provide the City's Office of Petroleum and Natural Gas Administration and Safety with timely information.

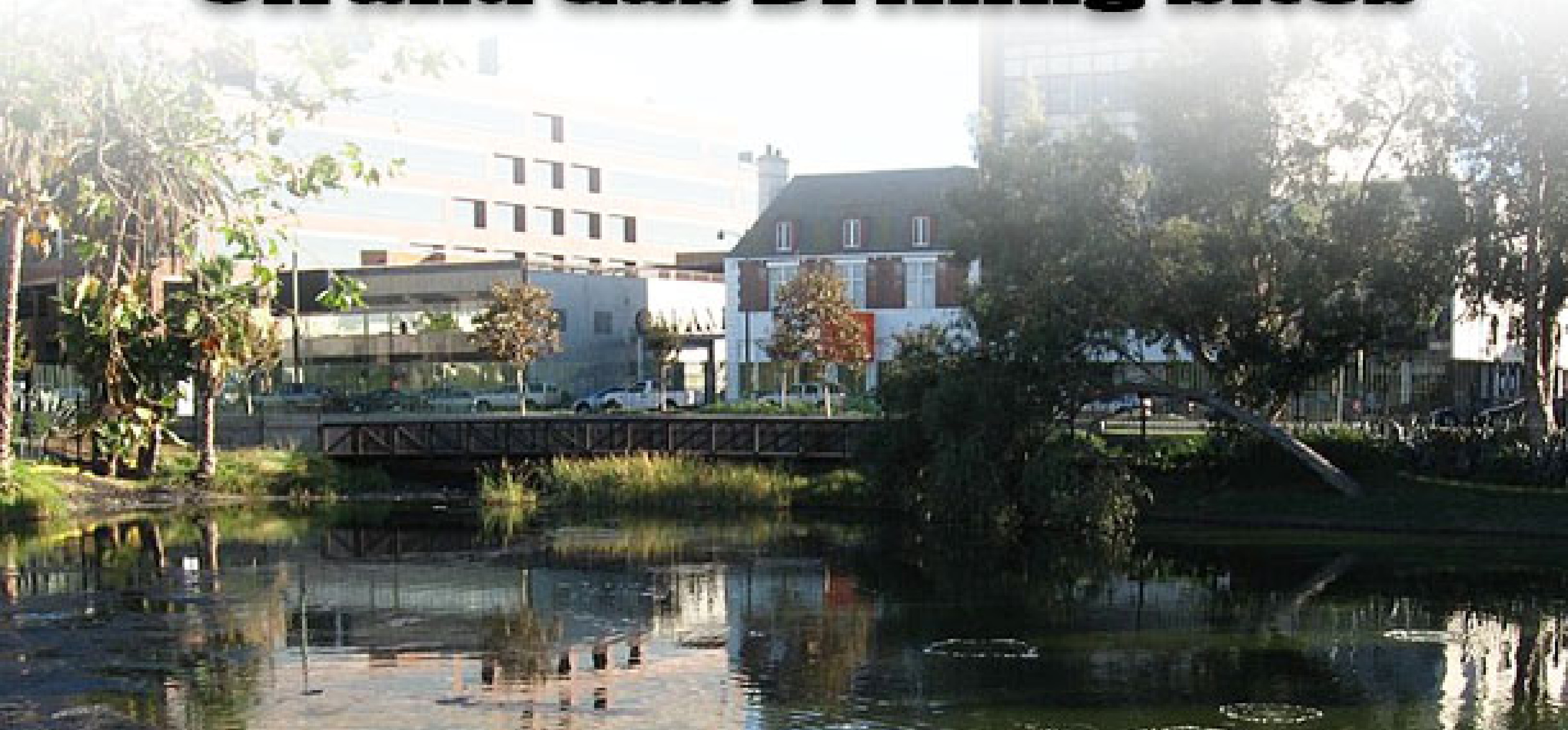
Why these recommendations matter: The City has made good strides as of late demonstrating its commitment to improving local control of oil and gas drilling, including the appointment of a Petroleum Administrator in 2016. We would like to thank the Petroleum Administrator and the Office of Petroleum and Natural Gas Administration and Safety for their work and ongoing cooperation. Moving forward, there is more officials can do to consider a more public-health focused path and take a deliberate, data rich approach to protect public safety, establish priorities and make policy decisions that reflect the unique risks associated with oil and gas drilling within our large urbanized City.

Respectfully submitted,

RON GALPERIN
Los Angeles Controller



Review of the City of Los Angeles' Oil and Gas Drilling Sites



Hancock oil field, (top, 1910), present day location of the LA Brea Tar Pits (bottom) Top photo: L.A. Public Library Photo Archives (top), Wikipedia (bottom)

RON GALPERIN

LA CONTROLLER

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EXECUTIVE SUMMARY

The history of the City of Los Angeles is closely tied to oil and gas drilling activity that began in the nineteenth century. Despite the City's growth into a densely-populated urban environment, oil and gas operations continue today in close proximity to non-industrial sites such as homes, schools, businesses, and parks. The City's challenge is how to effectively oversee existing wells.

According to the California Department of Conservation, Division of Oil, Gas, and Geothermal Resources (DOGGR), as of April 2018, there are approximately 5,000 known wells in the City.[1] Approximately 1,000 of these wells are active or idle, and the remaining wells are buried, or plugged and abandoned in accordance with State requirements. Further, approximately 77% of active and idle wells in the City are operated by six companies. The geographic distribution of wells overlaps with locations where large deposits of recoverable oil and gas were discovered.

Oil and gas drilling sites pose unique risks that can jeopardize public health or environmental quality, and the State is the primary regulator of the industry. Because of the State's regulatory authority, the City is generally preempted from controlling *how* oil and gas activities are carried out **below ground**. Nonetheless, the California State Constitution authorizes local governments to "make and enforce within its limits all local, police, sanitary, and other ordinances and regulations not in conflict with general laws [i.e., federal and State]." **Accordingly, the City can use its land use authority to determine *where* the activities are carried out and ensure that they are performed in accordance with local health and safety codes, as long as those codes do not conflict with federal or State laws.**

We initiated this review to determine if the City has:

- Established monitoring and enforcement programs to improve quality of life and public safety. We found that the City did not effectively enforce its land use decisions at drilling sites and we identified opportunities to improve how Fire Code inspections are performed.
- Required appropriate coverage to protect itself and its residents from financial risks associated with oil and gas wells. We noted the City does not have adequate insurance and surety bond requirements to protect taxpayers.
- Implemented effective processes to collect revenues and recover costs. We found that the City needs to do more to prioritize cost recovery, pursue new revenue streams, and ensure it receives the royalty revenue due from oil and gas operators.

For decades, City Departments tasked with carrying out responsibilities related to oil and gas activities did so without input from a professional with technical expertise to help establish priorities, coordinate efforts, and make informed decisions. Recent actions by City Policymakers demonstrate a commitment to improving local control: in September 2016 the City hired a full-time Petroleum Administrator, and members of the City Council recently expressed interest reorganizing the City's oversight framework.

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[1] DOGGR defines idle wells as wells that have been inactive for a period of 24 consecutive months (i.e., two years). Plugged and abandoned wells have been sealed with cement using techniques outlined by the State. Buried wells are typically older and are not abandoned to current standards; the mapped locations of those wells are sometimes only approximate.

Generally, we found that the City did not effectively exercise local control over oil and gas drilling sites due to the historical nature of drilling activity combined with a fragmented approach to oversight. This report and its related recommendations are intended to assist the City as it moves forward with efforts to improve oversight of oil and gas drilling sites, specifically as it relates to: (1) improving quality of life and public safety; (2) protecting City taxpayers' financial interests; (3) generating City revenue from oil and gas wells; and (4) increasing transparency and information sharing.

Improving Quality of Life and Public Safety

The City has taken a lax and reactive approach to monitoring, enforcing, and modernizing conditions of approval at oil and gas drilling sites. Upon granting land use approval, the Department of City Planning (DCP)/Office of Zoning Administration (OZA) establishes conditions under which a drilling site can operate (i.e., conditions of approval). These requirements are established on a site-by-site basis and are designed to mitigate nuisances such as foul odors, loud noises, bright lights, industrial traffic, vibrations, and other adverse effects. Documented evidence of noncompliance or ineffectiveness can be used to implement modified conditions of approval or require corrective actions.

Although the City's Department of Building and Safety (DBS) is responsible for enforcing the City's land use decisions, investigations about potential violations are only initiated based on complaints and, until recently, the City did not have a Petroleum Administrator to provide technical assistance. This approach limited the City's ability to document evidence that could be used to: (1) modify operating requirements to account for community concerns and surrounding land uses; and (2) modernize operating requirements to account for advances in technology, such as continuous air quality monitoring, and improved data management practices.

As it refines its Fire Code inspection program, the City should prioritize enhanced interdepartmental collaboration, and implement a risk-based approach to site selection. The Los Angeles Fire Department (LAFD) has an inspection and permitting framework to protect residents and property from hazards of fire, explosion, or panic. Each inspection performed by LAFD presents an opportunity to assess risk and share information with City Departments and regulatory agencies. Despite the City's recent efforts to reorganize its oversight approach, these inspections remain within a departmental silo. The effectiveness of the City's oversight efforts will remain constrained as long as these activities are not part of a larger, coordinated framework.

Currently, geographic proximity and date of last inspection are the primary factors considered when planning annual Fire Code inspections at oil and gas drilling sites. The LAFD needs to consider additional risk factors to make strategic decisions about which locations should be prioritized at the beginning of each inspection cycle.

To address these quality of life and public safety issues, the City should:

- **Identify** high-risk drilling sites, perform targeted reviews, document evidence of noncompliance, and take appropriate action to modify and modernize conditions of approval to include emerging technologies such as continuous air monitoring devices. These reviews should include input from residents and businesses located near high-risk drilling sites. *(Responsible entity: Petroleum Administrator in collaboration with DCP/OZA, the City Attorney and DBS)*

- **Prioritize** interdepartmental collaboration and plan annual Fire Code inspections using additional risk-based factors such as: (1) proximity to residential and other non-industrial sites; (2) age and number of wells; and (3) number and severity of previous Fire Code violations. *(Responsible entity: LAFD)*

- **Consider** development of an enhanced oversight program to proactively monitor/enforce conditions of approval at drilling sites. In addition, consider the development of a single, cohesive inspection program that leverages expertise across City Departments. *(Responsible entity: City Policymakers)*

- **Consider** amending the Los Angeles Municipal Code (LAMC) to allow the City to undertake periodic reviews of conditions of approval at all drilling sites. *(Responsible entity: City Policymakers)*

Protecting City Taxpayers' Financial Interests

The City does not have adequate insurance and surety bond requirements to protect taxpayers from well operators that knowingly or unknowingly cause harm to the public or environment. Operators of oil and gas wells located in the City are not required to maintain insurance policies with the City as a named party, despite the fact that clean-up costs from accidents such as well blowouts, oil/chemical spills, or groundwater contamination can be significant. In contrast, the City of Carson requires well operators to obtain policies such as control of well insurance, excess liability, and environmental impairment coverage that name the City of Carson, its officers, officials, agents, and employees as additional insured entities.

The City's current approach to limiting financial liability is through surety bond requirements. Well operators seeking to obtain an operational permit from LAFD or land use approval from DCP/OZA are required to post and maintain surety bonds. Currently, the City requires $10,000 surety bond per well or a blanket bond of $50,000 for any number of wells (or cash-in-lieu deposits) to ensure compliance with the Fire Code. In addition, the City requires a $5,000 surety bond to ensure compliance with zoning and conditions of approval. Generally, the purpose of the surety bonds is to ensure the City has access to funds if an operator is unable to absorb the costs of site remediation and well plugging and abandonment.

These bonding requirements have not been revised in decades. In addition, the City does not have a process to adjust for risk factors unique to each site such as well depth, methods of operation, operator history, and proximity to residents and sensitive environmental sites. The State has recently taken steps to increase its bonding requirements and remediation budget, but these resources may not be sufficient to cover costs associated with all orphan wells in the City of Los Angeles.

The City needs to improve its processes to ensure well operators maintain insurance and bond coverage. As the City develops insurance requirements for oil and gas operators, it should also establish minimum advance notification protocols about insurance policy renewals, revisions, and cancellations.

Currently, the City does not have adequate processes in place to ensure that operational and zoning surety bonds provided by well operators are still valid. Information provided by the Office of Finance, DCP/OZA, and City Administrative Officer (CAO) Risk Management Division showed that the City did not have a complete and accurate inventory of surety bonds and cash-in-lieu deposits. As a result, it is likely that older wells are no longer covered by active surety bonds due to insolvent surety companies.

To protect City taxpayers' financial interests, the City should:

- **Consider** policy changes to require all well operators to obtain and maintain a combination of adequate insurance coverage and surety bonds that reflect the unique public safety and environmental risks of operating a drilling site in a densely-populated urban environment. *(Responsible entity: City Policymakers)*
- **Consider** policy changes to require well operators to submit proof of bond/insurance coverage as part of annual applications for LAFD operational permits, and LAFD should upload bond/insurance documents to the City's electronic database. *(Responsible entity: City Policymakers)*
- **Perform** periodic reviews of bonds/insurance policies on file with the City, and file claims when irresponsible operators of drilling sites demonstrate noncompliance with legal requirements and conditions of approval. *(Responsible entity: Petroleum Administrator)*

Generating City Revenue from Oil and Gas Wells

Operators of oil and gas drilling sites are subject to several types of federal, State, and local taxes like other businesses operating in the City. The City can also generate revenue through industry-specific fees and extraction of oil and gas from City-owned property. Given the historical nature of drilling activity in the City, successful extraction of oil/gas from older wells is likely more challenging and expensive than in the past. Policymakers should consider these factors when evaluating taxes and fees from oil/gas extraction activity and develop an equitable framework that generates revenue for the City without discouraging business activity.

As it enhances the local oversight framework, the City should prioritize cost recovery. Successful implementation of the recommendations in this report, and the Council's interest in developing an enhanced local oversight framework, will require additional financial resources. Currently, the LAMC allows the City to recover costs only as related to processing land use applications and performing Fire Code inspections in conjunction with annual operational permits or specific-action permits. Moving forward, the City should ensure that additional costs associated with issuing licenses/permits, performing investigations/inspections, and administrative enforcement are borne by operators of drilling sites instead of taxpayers.

The City should consider reintroducing a barrel tax for voter approval. Many neighboring local jurisdictions assess a per barrel tax on oil that is extracted by well operators. The City previously had a barrel tax in place, however, the tax was repealed in 1996.[2] The City put forth a special ballot measure in 2011 that would have imposed a tax of $1.44 per barrel of oil extracted within the City. The proposed tax rate was significantly higher than barrel taxes imposed by neighboring jurisdictions. The proposed ballot measure was narrowly rejected by voters 51.07% to 48.93%.

Although the March 2011 ballot measure was narrowly rejected, increased awareness about the impacts of oil and gas extraction in densely populated environment combined with high profile public health incidents such as Aliso Canyon may have shifted voter opinion.

The City's inadequate oversight of oil and gas extraction from under (or "subsurface") City-owned property makes it unlikely that the City is realizing the related value from its real estate assets. The City's revenue generation strategies include: (1) participating in agreements whereby well operators are extracting oil or gas from subsurface parcels whose mineral rights are owned by the City; and (2) awarding leases to allow well operators to construct and operate drilling sites directly on City-owned property. In exchange, the City is entitled to a percentage of profits from the sale of oil or gas extracted from those locations. Under both types of agreements, the City would receive "royalty" payments.

Council-controlled and Proprietary Departments provided information that showed oil and gas operators paid $390,000 in royalty revenue in FY2017. However, we could not confirm the accuracy of these payments because: (1) the City does not currently know the locations of all subsurface parcels where it owns mineral rights and has participated in a pooling or unitization agreement; and (2) City Departments acknowledged that they did not have a process to verify that operators paid appropriate royalties.

In addition, lax oversight of oil and gas lease agreements increases the risk that City-owned property has not been restored to its original condition and therefore may include idle, orphan, or improperly plugged/abandoned wells.

To address these revenue-related issues, the City should:

- **Amend** the LAMC to allow the City to recover regulatory fees associated with an enhanced local oversight framework for oil and gas drilling sites. *(Responsible entity: City Policymakers)*
- **Perform** a cost-benefit analysis for implementing a barrel tax that considers factors such as: (1) projected extraction volume based on historical records and likelihood of future drilling activity; (2) cost of placing the measure on the ballot; (3) ongoing administrative costs with imposing and collecting the tax; and (4) the appropriate tax rate. *(Responsible entity: City Policymakers)*
- **Direct** all Departments to verify any oil or gas exploration on or under property they control. Once an inventory has been developed, determine whether to renew and

[2] The City currently assess a business tax ($1.01 per $1,000 in gross receipts) on wholesale sales of oil or gas that is extracted within City limits.

renegotiate any expired lease agreements. In addition, oversight responsibility for all oil and gas extracted from City-owned properties should be formally transferred to the Petroleum Administrator. *(Responsible entity: City Policymakers)*

- **Perform** title research of land records to identify subsurface parcels whose mineral rights are owned by the City. For those related to oil fields with active extraction activity, determine whether the City received appropriate royalty payments. For well operators who did not pay the City royalties it was owed, consult with the City Attorney to explore legal options. *(Responsible entity: Petroleum Administrator)*

- **Collaborate** with LAFD and State regulators to identify lessees who did not restore City-owned property previously used for oil/gas exploration to its natural condition or comply with State plugging/abandonment requirements. Propose remedial/legal actions for lessees who did not fulfill their obligations. *(Responsible entity: Petroleum Administrator)*

- **Develop** an improved reporting process to provide assurance of compliance with lease requirements, including periodic reviews of royalty payments. *(Responsible entity: Petroleum Administrator)*

Increasing Transparency and Information Sharing

Because it lacks comprehensive and reliable information about oil and gas drilling sites, the City cannot effectively facilitate coordination between Departments or make timely, data-driven policy and operational decisions. We noted the City did not have: (1) an independently verified inventory of well locations that matched the inventory maintained by the State; (2) an electronic database of conditions of approval for all oil and gas drilling sites; and (3) a mechanism to require well operators or external regulatory agencies to notify the City when permits are issued, operators are cited for violations, or complaints are filed.

To address these transparency and information sharing issues, the City should:

- **Improve** access, timeliness, and reliability of information related to oil and gas drilling sites. This information should be compiled and connected in a manner to facilitate informed decision-making and improve interdepartmental and interagency coordination. As the City builds a centralized and reliable repository of information, it should also prioritize development of a public-facing website to increase transparency and facilitate public engagement on issues related to oil and gas drilling sites. *(Responsible entity: Petroleum Administrator)*

- **Consider** policy changes that require operators of oil and gas drilling sites to provide the Petroleum Administrator with timely notifications of complaints and communications to and from external regulatory agencies. *(Responsible entity: City Policymakers)*

CONCLUSION

City Departments are responsible for performing a variety of tasks related to oil and gas drilling sites such as making land use decisions, issuing permits, performing inspections, enforcing code requirements, protecting the City's financial interests, and leasing City-owned property for oil exploration and extraction. For decades, the City had no expert on staff to coordinate these activities or provide input in the form of technical assistance. The City's historically fragmented approach led to inadequate oversight of oil and gas drilling sites. Council's recent interest in reorganizing the City's oversight framework, and establishing a dedicated Office of Petroleum and Natural Gas Administration & Safety (OPNGAS), demonstrate a renewed commitment to improving local control.

The oversight of oil and gas drilling sites is a critical function that impacts residents' health and quality of life. The Los Angeles County Department of Public Health has issued a report on public health risks that highlights the importance of: (1) site-specific assessments to determine appropriate setback distances from sensitive land uses; (2) working with State regulators to implement requirements for continuous air monitoring systems at drilling sites located near urban areas; and (3) improved local oversight through coordination and data-sharing.

As the City moves forward, it should consider this public-health focused guidance and take a deliberate and data-driven approach to establishing priorities, designing programs, and making policy decisions that reflect the unique risks associated with oil and gas drilling within our large urbanized City.

On June 4, 2018, a draft of this report was provided to the Board of Public Works – Office of Petroleum and Natural Gas Administration and Safety (OPNGAS), Los Angeles Fire Department, Los Angeles Department of Building and Safety, Department of City Planning/Office of Zoning Administration (DCP), Office of Finance, the Risk Management Division of the Office of the City Administrative Officer, General Services Department, Library, Recreation and Parks, Harbor Department, and Los Angeles Department of Water and Power. We met with OPNGAS at an exit conference on June 7, 2018 and invited comments from the management of each of the departments indicated. We considered those comments as we finalized this report for issuance. We would like to thank the Board of Public Works, OPNGAS, and staff from other City Departments for their time, expertise, and cooperation during this special review.

The City's status as a leading business, trade, and cultural center would not be possible without its industrial past. The discovery of oil near present-day Dodger Stadium at the end of the nineteenth century played a critical role in the City's development. The ensuing decades brought significant population growth and oil production; by 1930 the City's population grew to 1.2 million and the State was producing one quarter of the world's oil output.[3] Subsequent drilling overlapped with continued population growth.

Figure 1: Los Angeles City Oil Field (circa 1900)

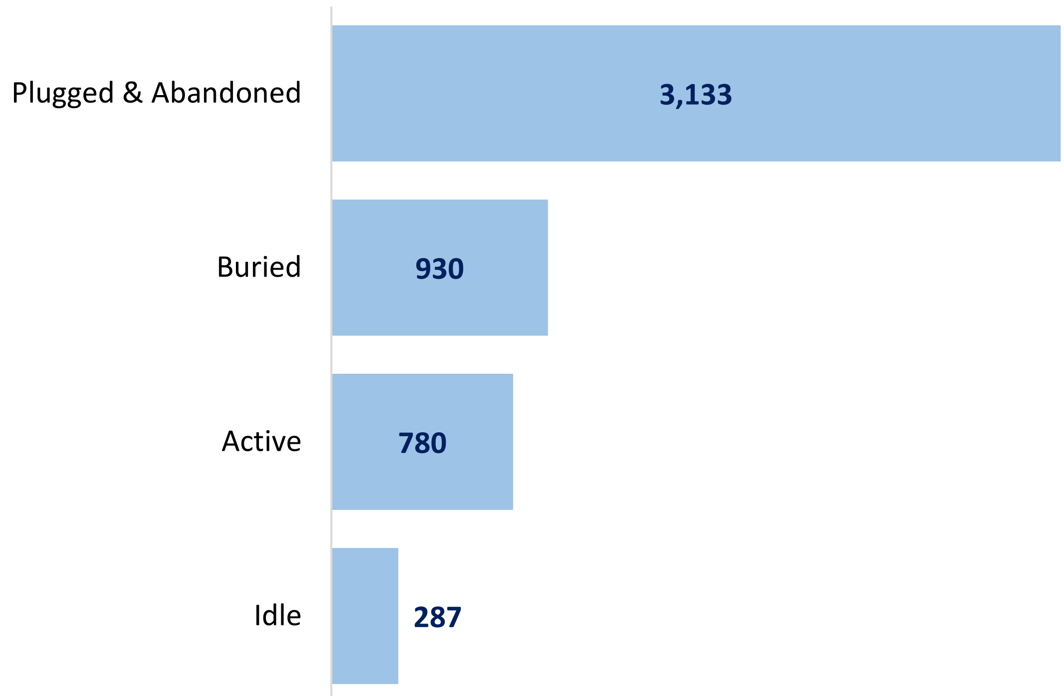
<u>Source</u>: California State Library

Regardless of whether oil and gas wells were drilled in established residential neighborhoods, or residential development followed after the drilling sites were established, the end result was the same. Today, a number of the City's active, idle, buried, and abandoned oil and gas wells are located in close proximity to homes, schools, hospitals, and other non-industrial sites. Further, many of the wells were initiated and/or abandoned prior to the establishment of modern federal, State, and local regulations.

According to the California Department of Conservation, Division of Oil, Gas, and Geothermal Resources (DOGGR) database, there are more than 5,000 known wells in the City of Los Angeles as of late-March 2018. DOGGR reported the status of those wells as follows:

[3] Taylor, Alan. "The Urban Oil Fields of Los Angeles." *The Atlantic,* August 26, 2014. https://www.theatlantic.com/photo/2014/08/the-urban-oil-fields-of-los-angeles/100799/

Figure 2: Number and Status of Oil and Gas Wells in the City[4]



Source: CA Department of Conservation Division of Oil, Gas, and Geothermal Resources (DOGGR)

DOGGR data indicates that a small group of companies are responsible for ongoing oil and gas extraction; approximately 77% of active and idle wells in the City are operated by six companies. This group is comprised of the following companies: Warren E&P (224 wells); Freeport-McMoRan Oil & Gas LLC (217 wells); Tidelands Oil Production Company (183 wells); Southern California Gas Company (78 wells); Pacific Coast Energy Company LP (59 wells); and Brea Canon Oil Company (57 wells).

The City's Municipal Code (LAMC) defines an oil well as "any well or hole already drilled, being drilled, or to be drilled into the surface of the earth which is used or intended to be used in connection with…producing petroleum, natural gas, or other hydrocarbon substances." The LAMC categorizes oil and gas wells as either production wells ("Class A") or injection wells ("Class B"). Generally, Class A wells are designed to extract oil and gas substances from subsurface locations and Class B wells are used to inject substances such as oil field waste, gas, water, or

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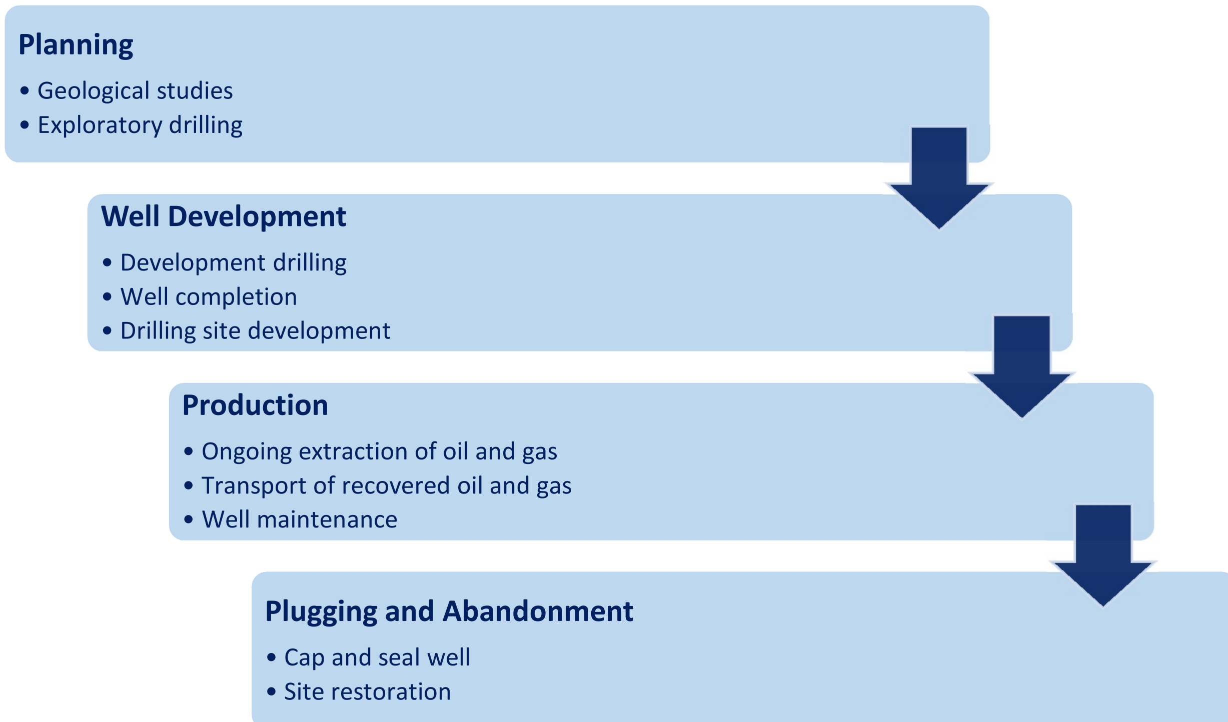
[4] Plugged and abandoned wells have been sealed with cement using techniques outlined by the State. Buried wells are typically older and are not abandoned to current standards and the mapped locations of these wells are sometimes approximate. As of January 2018, DOGGR defines idle wells as wells that have been inactive for a period of 24 consecutive months (i.e., two years) but can still be reactivated.

other substances into subsurface locations. The graphic below provides an overview of the process by which wells are established, activated, and abandoned.

Figure 3: Typical Life Cycle of a Well



Los Angeles Fire Department (LAFD) records indicate that there are more than a dozen large drilling sites across the City that include many of the active and idle wells listed in Figure 2. A single drilling site can consist of multiple wells, large pieces of industrial equipment, storage tanks, boilers, pumps, pipelines, pressure vessels, and other types of machinery and equipment.

Regulatory Framework

Oil and gas drilling sites pose unique risks that can jeopardize public health or environmental quality. Once a well has been drilled and easily accessible oil deposits have been extracted, operators may use enhanced recovery techniques that involve the subsurface injection of steam, gases, or chemicals to bring oil to the surface. Depending on the location of the drilling site, these chemicals may be transported through residential neighborhoods. Public health and environmental risks are not limited to active drilling sites; buried and idle wells can leak methane or contaminate drinking water. Given the number and magnitude of risks, several governmental entities are tasked with regulating oil and gas extraction activities.

The U.S. Department of the Interior, Bureau of Land Management oversees oil and gas drilling activities on federal land. However, regulation of oil and gas drilling activities on non-federal land is largely left to the State. DOGGR supervises the drilling, operation, maintenance, and plugging/abandonment of oil and gas wells. Entities seeking to engage in oil and gas activities are required to obtain approval from DOGGR and submit monthly reports detailing the volume of oil and gas that was extracted.

There are additional State-level regulatory agencies tasked with protecting the public from health and environmental risks associated with oil and gas extraction activities. Under the oversight of the California Air Resources Board (CARB), the South Coast Air Quality Management District (SCAQMD) is the air pollution control agency for all of Orange County and the urban portions of Los Angeles, Riverside, and San Bernardino counties. Every piece of stationary equipment in the City that emits or controls air pollution must be permitted by SCAQMD. In March 2017, CARB approved new regulations designed to detect and reduce methane leaks from oil and gas facilities.

Because of the State's regulatory authority, the City is preempted from controlling *how* oil and gas activities are carried out. Nonetheless, the California State Constitution authorizes local governments to "make and enforce within its limits all local, police, sanitary, and other ordinances and regulations not in conflict with general laws [i.e., federal and State]." Accordingly, the City can use its land use authority to determine *where* the activities are carried out and ensure that they are performed in accordance with local health and safety codes, as long as those codes do not conflict with federal or State laws.

City Departments' Roles and Responsibilities

There are several City Departments responsible for a wide range of approval, enforcement, and oversight of activities pertaining to oil and gas drilling. Operators of oil and gas drilling sites are subject to remitting City business and utility taxes, and some City Departments have leases with private companies to operate oil and gas wells on City-owned property. Lastly, the City established an Office of Petroleum Natural Gas Administration and Safety in 2016, intended to coordinate all matters related to the exploration for oil and gas in the City. The specific roles and responsibilities for each of these departments/offices are detailed below.

Land Use Approval to Establish a Drilling Site

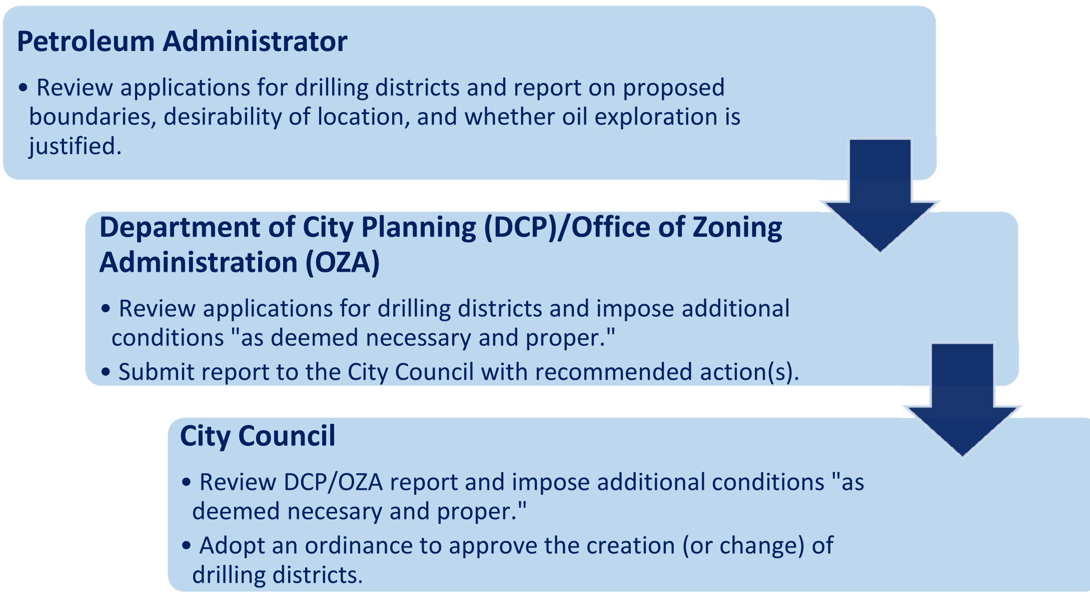
In addition to regulatory approval from DOGGR, operators must obtain land use approval from the City before establishing a drilling site. Land use decisions by planning officials related to drilling sites are discretionary and must weigh existing General Plan Policies, Goals, and Objectives along with the interests of the surrounding community.

The City's land use framework that dictates where and under what conditions oil and gas exploration can occur is outlined in the LAMC. This framework was originally established in 1946, decades after significant oil and gas exploration activity had already occurred within the region. Currently, the LAMC outlines a two-step process for obtaining land use approval from the City: establishment of an oil drilling district; and establishment of an oil drilling site.[5]

[5] According to the City's zoning code, land use approval to establish a drilling district or site in the M3 Zone ("Heavy

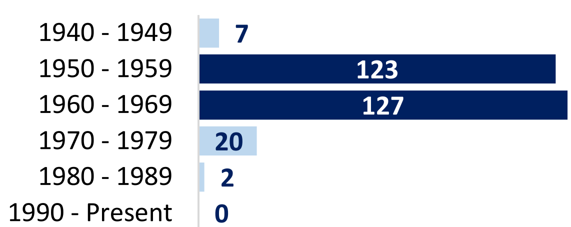
The LAMC divides the City into areas within which oil drilling districts can be established. Each area has a set of standard conditions that establish the minimum size of oil drilling districts, the allowable number and density of drilling sites and individual wells, and fencing and landscaping requirements. The graphic below outlines the process by which the City reviews and approves applications for oil drilling districts.

Figure 4: Establishing an Oil Drilling District



The City has not established a new drilling district in decades; a review of drilling district ordinances provided by DCP/OZA showed that the most recent drilling district was established in 1984 and a large number of drilling districts were established in the 1950s and 1960s. Some of these drilling districts were later terminated by the City but are included in Figure 5 to show the large amount of oil and gas exploration activity that occurred during the middle of the twentieth century.[6]

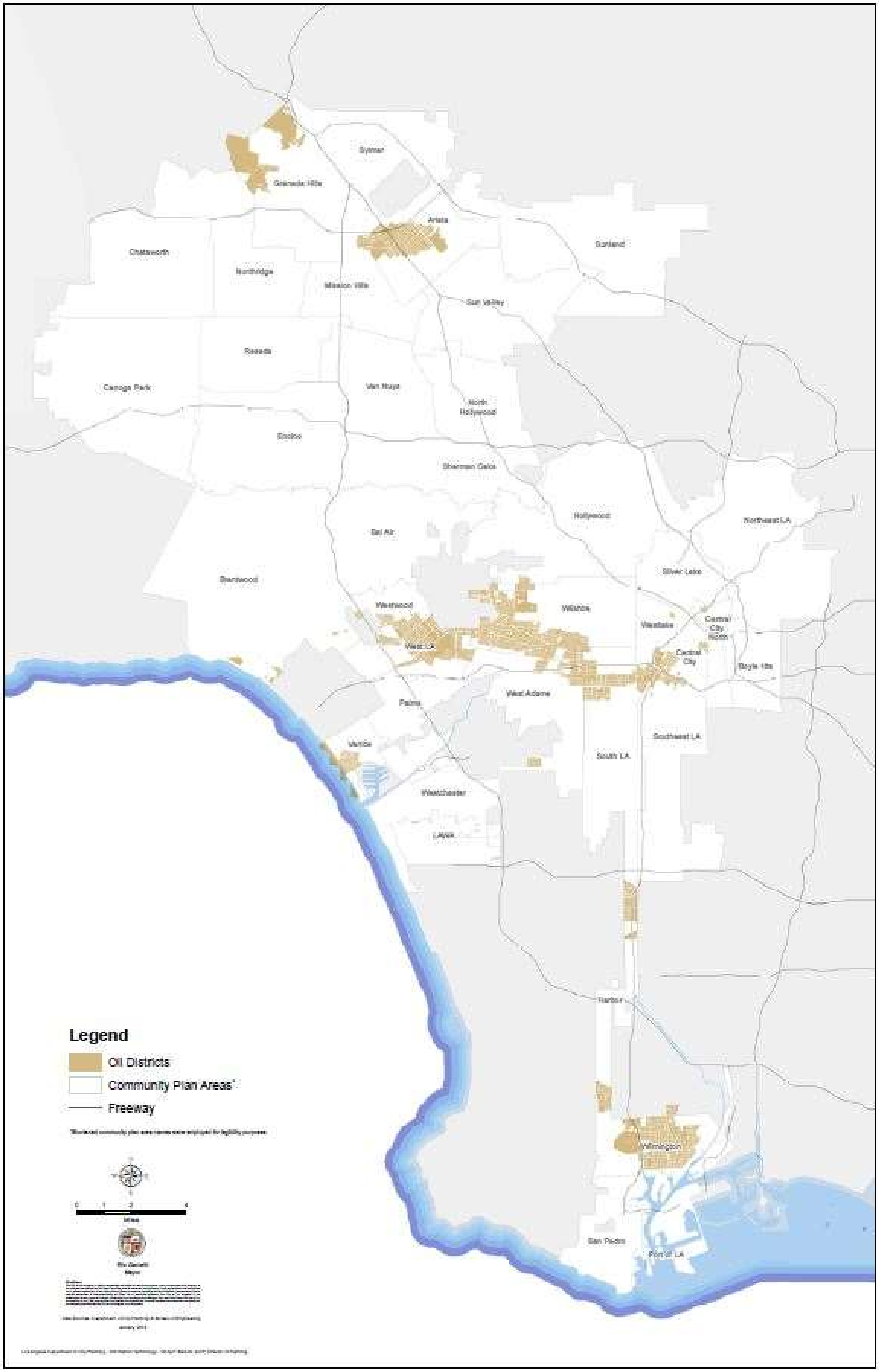
Figure 5: Oil Drilling Districts Established by Decade



Industrial”) is not required unless the activity occurs within 500 feet of a more restrictive zone.

[6] DCP/OZA also provided documents that showed drilling district locations, establishment dates, and ordinance numbers but did not include corresponding ordinance language. These drilling districts may have been established in the 1950s (or prior) but were not included in Figure 5.

Figure 6 below shows the City's current drilling districts.



Once an oil drilling district has been established by ordinance, anyone seeking to "drill, deepen, or maintain an oil well or convert an oil well from one class to another [e.g., production to injection]" must file an application with DCP/OZA to request a determination of the conditions of approval under which the site can operate. Conditions of approval vary from site-to-site, however, the general purpose is to protect residents and property adjacent to the drilling site and ensure the operation is not a nuisance. If the application is approved, DCP/OZA sends the operator a letter of determination with a list of conditions. According to the Petroleum Administrator, no new drilling sites have been established in recent years; yet a challenge remains in how the City effectively regulates existing (i.e., "grandfathered") drilling sites.

Historically, DCP/OZA processed applications for modifications to original conditions of approval using a limited review process, which did not require an Environmental Impact Report or public participation. In September 2016, DCP/OZA agreed to follow a more comprehensive review process for (new) applications under the Municipal Code, including environmental review pursuant to the California Environmental Quality Act (CEQA), increased notification requirements to affected stakeholders, and public hearings. DCP/OZA staff indicated that no new applications have been received since the change in the City's review process.

Oversight of Oil and Gas Drilling Sites

Once a drilling site has been granted land use approval, there are various one-time and ongoing responsibilities assigned to City Departments to ensure that operators are in compliance with conditions of approval and local public safety codes. These functions are primarily assigned to the Department of Building and Safety (DBS) and Los Angeles Fire Department (LAFD).

Figure 7: Monitoring and Enforcement Activities Assigned to City Departments

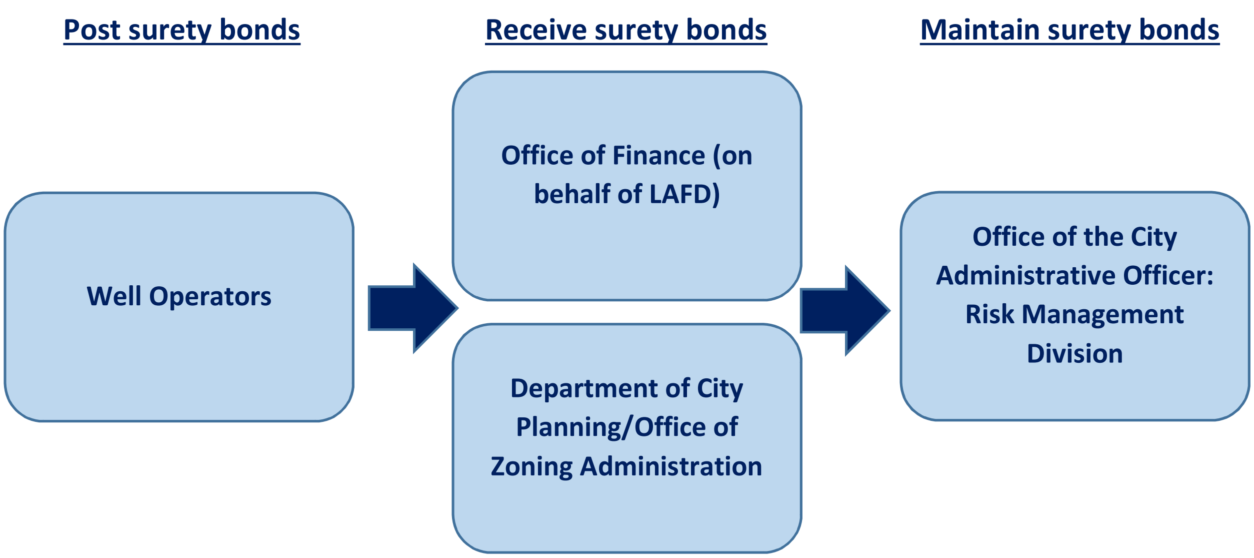
LAFD is also designated by the State as a Certified Unified Program Agency (CUPA) and is required to apply statewide standards to each facility in its jurisdiction that treats or generates hazardous waste, operates underground storage tanks, or stores hazardous material. Drilling sites with these items must be inspected and permitted to ensure compliance with State requirements.

Oil and Gas Well Bonds

In addition to activities to mitigate operational risks, the City has a system in place that is intended to limit exposure to financial risks associated with oil and gas drilling activities. Well operators seeking to obtain an operational permit from LAFD or land use approval from DCP/OZA are required to file and maintain surety bonds with the City. The purpose of the bonds is to ensure the City has financial resources available in the event the operator is unable to remediate issues related to Fire Code or land use violations. Operators are required to maintain active bonds until LAFD has determined that the well has been plugged and abandoned in accordance with DOGGR requirements.

The process by which bonds are posted and maintained are outlined in the graphic below.

Figure 8: Posting and Maintaining Surety Bonds



Prior to 2005, the City Attorney was responsible for maintaining the bonds to ensure they were enforceable in the event a claim needed to be filed. Since 2009, the Office of the City Administrative Officer (CAO) Risk Management Division has maintained an online system ("Track4LA") to streamline the processing, tracking, and verification of insurance policies and bonds submitted by contractors, vendors, and permittees.

Revenue

In addition to the activities described above, the City can exercise local control of oil and gas drilling sites through various revenue generation and cost recovery strategies. Generally, these revenues fall into two categories: (1) taxes applicable to all businesses operating in the City; and

(2) industry-specific strategies, including extraction (i.e., “barrel”) taxes; fees to recover local regulatory costs; and revenue sharing agreements with private well operators that allow for oil/gas extraction from subsurface locations where the City owns the mineral rights.

Coordination

Given the number of City Departments tasked with responsibilities associated with oil and gas drilling sites, the City has established a framework to help ensure these activities are coordinated by a professional with technical and administrative expertise.

Board of Public Works, Office of Petroleum and Natural Gas Administration and Safety

The City hired a full-time Petroleum Administrator in September 2016 to improve oversight of petroleum and natural gas operations. The Petroleum Administrator was placed under the Board of Public Works in the Office of Petroleum and Natural Gas Administration and Safety (OPNGAS). The Los Angeles Administrative Code (LAAC) tasks the Petroleum Administrator with a broad range of responsibilities including:

- coordinating all matters respecting or concerning the exploration for, or production of, petroleum in the City;
- making recommendations concerning matters related directly or indirectly to the exploration for, or production of, petroleum within the City;
- reporting, upon request, to any department, bureau or office of the City regarding the creation of drilling districts;
- establishing rules and procedures for leasing of City-owned property for oil and gas exploration or production;
- administering and determining compliance with all provisions of oil and gas leases; and
- investigating and making recommendations concerning existing restrictions on exploration for, and production of, petroleum in the City.

The City did not have a full-time, qualified Petroleum Administrator on staff for approximately 30 years and the responsibilities delineated above were handled on an ad hoc basis by analysts who did not have a technical background in oil and gas matters.[7] As a result, the effectiveness of local oversight diminished because the City lacked input from a professional with technical and administrative expertise.

During this review, members of the City Council introduced a motion seeking to centralize oversight of oil and gas activity in the City under the Board of Public Works. One of the stated goals of the reorganization is to modernize the City's oversight structure to "enhance public safety, provide greater efficiency in deliver[ing] high quality public services, improve communications, and strengthen public health protections." Specifically, the motion tasks the Petroleum Administrator and City Departments with:

[7] The LAAC previously assigned these responsibilities to the Office of the City Administrative Officer (CAO).

- identifying functions performed by City Departments that can be transferred to OPNGAS;
- identifying the budget resources and LAMC amendments to facilitate the transfer of functions to OPNGAS;
- recommending operational improvements such as data management, community participation, and enhanced permitting and inspection activities; and
- recommending methods to integrate workflows and increase interdepartmental and interagency collaboration.

In March 2018, members of the City Council introduced a motion requesting that OPNGAS and DCP develop a plan to implement annual compliance checks to ensure oil and gas drilling sites are meeting appropriate regulatory standards and mitigating negative impacts. OPNGAS completed a preliminary assessment of the resources needed for an inspection program and requested funding to perform a fee study.

These efforts indicate that Policymakers are seeking a more defined and enhanced role for OPNGAS moving forward. Issues and recommendations regarding coordination and information sharing are included in Section IV of this report.

SECTION I: IMPROVING QUALITY OF LIFE AND PUBLIC SAFETY

The City can exercise local control of oil and gas drilling sites through its land use authority and local health and safety codes. Given the risks associated with oil and gas drilling sites, effective monitoring and enforcement activities to prevent and detect noncompliance are essential to protecting residents and property.

Quality of Life

Operators seeking to establish drilling sites in the City must obtain land use approval from DCP/OZA. Similar to other land use decisions in the City, DCP/OZA staff must respect the applicant's property rights and consider the compatibility of the proposed activities with the surrounding area. The industrial nature of oil and gas extraction means that drilling sites may be responsible for foul odors, loud noises, bright lights, industrial traffic, vibrations, and other adverse effects. The LAMC authorizes DCP/OZA to implement rules that operators must follow (i.e., conditions of approval) to mitigate the impact of these activities.

Conditions of approval vary from site-to-site, however, the general purpose is to protect residents and property adjacent to the drilling site and ensure the operation is not a nuisance. Once the conditions have been established, effective monitoring and enforcement is important as many drilling sites are located in close proximity to non-industrial sites such as homes, schools, and parks. Documented evidence of noncompliance can be used by DCP/OZA to implement modified conditions and/or corrective actions.

The City Has Missed Opportunities to Document Evidence of Violations of Conditions of Approval at Drilling Sites, but Recent Efforts Demonstrate Progress

Many of the drilling districts and sites in the City were established during the 1950s and 1960s. Generally, conditions of approval for existing drilling sites remain in perpetuity. While the LAMC allows DCP/OZA to impose additional conditions or require corrective actions, there is no mechanism in place to periodically assess whether the original conditions are still appropriate or effective. As a result, conditions of approval for older drilling sites may not consider advances in technology, improved data management practices, and surrounding land uses.

Historically, the City has taken a lax and reactive approach to monitoring and enforcing compliance with conditions of approval at oil and gas drilling sites. Evidence of violations has not been documented and the City has not made a concerted effort to modify and modernize operating requirements to account for community concerns and surrounding land uses.

The LAMC allows additional conditions or corrective measures to be imposed if there is demonstrated evidence that additional conditions are necessary to provide greater protection to residents and surrounding property. According to DCP/OZA, the following types of evidence can be used to initiate this process:

- failure to comply with existing conditions of approval;
- regulatory or Municipal Code violations; or
- a pattern of complaints backed by evidence that demonstrates the site is a nuisance to the community.

The LAMC also allows the City to implement additional conditions when operators of drilling sites submit an application to DCP/OZA to drill, deepen, or maintain a new or existing well.

The City has recently taken steps toward implementing modified conditions of approval at a drilling site in South L.A. that may serve as a model for future oversight activities.[8] The drilling site was originally established in 1965 and in recent years, residents living adjacent to the site have complained about its incompatibility with the surrounding neighborhood and accused the site operator of noncompliance with conditions of approval. In September 2016, DCP/OZA staff requested that the operator file a new Plan Approval application for a review of compliance with existing conditions of approval. The operator did not comply with the request and DCP/OZA staff and the Petroleum Administrator initiated a review of records maintained by City Departments and external regulatory agencies, conducted site visits, and held a public hearing to determine: (1) if the operator was complying with conditions of approval; and (2) if the existing conditions adequately protect the surrounding community.

Based on their efforts, DCP/OZA and the Petroleum Administrator found that since 2001, the operator obtained approval from DOGGR for at least 42 oil well maintenance and re-drilling jobs without requesting a determination of conditions of approval from DCP/OZA, as required by the LAMC. DCP/OZA also concluded that the operator failed to comply with requirements to effectively mitigate issues related sound, odor, light pollution, and the appropriate handling of hazardous materials. To address these findings, DCP/OZA issued a new letter of determination with modified conditions, which include:

- enclosing drilling equipment in a 45-foot structure;
- several technology-focused improvements to allow real-time monitoring of the site;
- increased restrictions on industrial traffic in the neighborhood; and
- filing a Plan Approval application within two years to review compliance with the modified conditions.

As described above, DCP/OZA is authorized to require an operator to file an application for modified conditions of approval as a means to abate a nuisance or address non-compliance with existing conditions. However, this process is not possible unless the City has documented evidence of noncompliance or nuisance operations.

Missed Opportunities to Document Evidence of Violations

DBS is responsible for enforcing the City's zoning ordinances, including compliance with conditions of approval established by DCP/OZA. The LAMC provides DBS with authority to conduct inspections to enforce land use decisions and compliance with various building regulations (e.g., Building Code, Electrical Code, Plumbing Code). However, we found that DBS does not use this authority to perform proactive monitoring and enforcement of conditions of approval at oil and gas drilling sites.

[8] In April 2018, the operator filed a lawsuit challenging the City's right to impose additional conditions and seeking to set aside the determination in full. The trial in the matter is not expected to take place until 2019.

DBS staff stated that investigations about potential violations are initiated based on complaints about issues within their authority; complaints about non-DBS issues are referred to other City Departments. However, the information management challenges described in this report make it unlikely that DBS received notification of all relevant complaints. DBS also noted that some of the conditions of approval they are tasked with enforcing are outside their area of expertise and, until September 2016, the City lacked a full-time Petroleum Administrator that could provide technical assistance on these matters. As a result, the City missed opportunities to document evidence of violations at drilling sites.

These issues are not new. The need for a proactive code enforcement program to monitor and enforce compliance with conditions of approval at oil and gas drilling sites was outlined in a City Planning report to the City Council in November 2014. The report suggested that DBS' proactive monitoring and enforcement of businesses such as junkyards, auto body shops, recycling centers, and used car lots could be used as a model for the new program. For those sites, DBS is required to perform annual inspections to verify compliance with minimum standards included in the LAMC. Fees to cover the cost of performing the inspections are paid by property owners or business operators. However, a proactive enforcement program for oil and gas drilling sites was not developed; DBS' approach remains reactive.

A Way Forward

Although DBS is responsible for enforcing compliance with conditions of approval at drilling sites, there are obstacles that have prevented it from effectively performing those duties. DBS cannot enforce what it does not know; documents outlining conditions of approval for older drilling sites are stored in DCP/OZA files or in the City Archives. In addition, DBS inspectors may lack the technical expertise to evaluate whether the equipment and operations at a drilling site are appropriate.

These limitations suggest that simply providing DBS with additional resources to increase the number of available inspectors may not be enough. Although recent efforts by DCP/OZA and the Petroleum Administrator were a reactive approach to longstanding issues, they demonstrated that a targeted interdepartmental response can be used to document evidence of violations or nuisance operations. There may be additional sites in close proximity to residential neighborhoods that have not been subject to comprehensive review during the decades-long period when the City lacked a Petroleum Administrator. Investigations of these high-risk sites should be prioritized as the City develops a proactive monitoring and enforcement program.

Proactive, thorough inspections are critical to ensure compliance with conditions of approval. However, an inspection represents a snapshot in time, and may not be representative of the continuing day-to-day activities at a drilling site. The City's recent efforts at the South L.A. drilling site described above are notable for utilizing emerging technologies to improve the City's ability to monitor quality of life and public safety issues on an ongoing basis. Specifically, the City is requiring the operator to install and maintain the following:

- a fence-line air monitoring system that provides real-time air quality data via a website that also generates quarterly reports for SCAQMD, the Petroleum Administrator, and DCP/OZA;

- an early detection system to notify LAFD when hydrogen sulfide or methane is detected;
- acoustic, vibration, and video monitoring systems to track noise/vibration issues, and determine the cause(s) of a disturbance.

Additional technologies, such as the use of drones or other tools with advanced sensing technologies, can improve the City's ability to monitor and detect unfavorable issues at drilling sites. The City should prioritize incorporating these types of technologies into modified conditions and development of a single, cohesive inspection program that leverages expertise across all City Departments.

In addition to site-specific investigations to identify noncompliance, the City needs a mechanism to periodically review conditions of approval for ***all*** drilling sites in order to ensure that it is protecting residents from public health risks, effectively utilizing emerging technologies, and considering surrounding land uses. The Petroleum Administrator should collaborate with City Policymakers to determine an appropriate interval for these citywide reviews (e.g., every five years).

Public Safety

In addition to land use controls to ensure drilling sites are not a nuisance to the surrounding community, the City has a recurring inspection and permitting framework to protect residents and property from hazards of fire, explosion, or panic. Anyone seeking to establish or maintain an oil or gas well must obtain an operational permit from LAFD for each well that has not been appropriately abandoned (i.e., all active and idle wells). LAFD also requires specific-action permits for activities such as drilling, re-drilling, and well abandonment. For both operational permits and specific-action permits, the LAMC tasks the LAFD with performing investigations and granting approval, conditional approval, or denial of the application. By issuing the permit, LAFD is attesting that the well (and drilling site) does not create any undue hazards and is compliant with the City's Fire Code. LAFD has the authority to revoke or suspend permits due to violations of the Fire Code or when necessary for the protection of life and property.

Given the inherent risks of oil and gas operations and the large number of wells located throughout the City, regular and thorough Fire Code inspections are needed to protect public safety. Prior to 2017, the Fire Code inspections were performed by the LAFD's Harbor Industrial Unit (LAFD-HIU) in San Pedro. This function was transferred to the LAFD-CUPA unit in late 2017 due to personnel changes and organizational restructuring, however, responsibility for Fire Code inspections is being returned to LAFD-HIU due to LAFD-CUPA taking on additional responsibilities related to hazardous waste inspections. LAFD-CUPA staff have begun working on transferring the program back to LAFD-HIU and indicated that the current plan is to maintain the existing staffing model (i.e., one inspector for all active and idle wells).

The City Should Prioritize Annual Fire Code Inspections Using a Risk-Based Approach

The LAMC requires the Fire Marshal (or designee) to investigate applications for operational permits ***before*** making a decision and instructing Finance to issue or deny the permit. The investigation and operational permit issuance process outlined in the LAMC does not distinguish between applications submitted for new wells and renewal applications submitted for existing wells. Although a new drilling site has not been established in recent years, Finance and LAFD staff agreed that an inspection demonstrating compliance with the Fire Code would be required prior to the issuance of a new operational permit. In contrast, renewal applications for existing wells are renewed automatically upon receipt of payment, and Fire Code inspections are performed throughout the calendar year.

Although an inspection only provides a snapshot of the site's compliance with the Fire Code, the annual inspection cycle provides an opportunity to make strategic decisions about which locations should be prioritized. LAFD-CUPA staff indicated that factors such as geographic proximity and date of last inspection have guided their selection of locations since they began performing inspections in October 2017. As the City transfers this function back to LAFD-HIU, it should consider additional risk factors when deciding which locations to inspect at the beginning of each year. These risk factors include: (1) proximity to residential and other non-industrial sites; (2) age and number of wells; and (3) number and severity of previous Fire Code violations cited by LAFD.

The City Should Enhance Interdepartmental Collaboration as it Refines its Fire Code Inspection Program

Because DBS does not proactively inspect oil and gas drilling sites to ensure compliance with conditions of approval, the annual Fire Code inspections performed by LAFD are the City's primary tool to monitor activity at oil and gas drilling sites. Although LAFD's responsibilities are limited to enforcement of the Fire Code, each inspection presents an opportunity to assess risk and collect and disseminate information to other City Departments and external regulatory agencies.

Recent actions by City policymakers to improve local control (i.e., hiring a Petroleum Administrator and working to reorganize the oversight framework) demonstrate a commitment to mending the fragmented approach of the past. However, LAFD's process of performing Fire Code inspections, and information about those inspections, remains within a departmental silo. Currently, a single LAFD inspector is assigned to inspect more than 1,000 active and idle wells throughout the City on an annual basis. Operators who are cited for violations of the Fire Code are provided an opportunity to remediate the issue, and instances of continued noncompliance are forwarded to the City Attorney for follow-up actions. Information about Fire Code inspections and violations was previously recorded in the LAFD's Fire Prevention Application (FPA) system and until the recent decision to return control to LAFD-HIU, LAFD-CUPA staff began migrating the data to its Envision Connect data management system. Access to FPA and Envision Connect is limited to LAFD personnel; the software is housed on an LAFD server.

LAFD's approach may meet its needs based on LAMC requirements to enforce the Fire Code at drilling sites. However, the effectiveness of the City's oversight efforts will remain constrained if these activities are not part of a larger, coordinated framework. For example, a recurring pattern of Fire Code violations may alert other City Departments to potential issues such as noncompliance with conditions of approval or violations of the City's building codes (e.g., electric or plumbing codes). Technical assistance from the Petroleum Administrator could be used to identify high-risk sites that should be inspected more frequently. Photos of drilling sites and equipment could be used to track modifications to the site, or be used to compile information for a more centralized database that begins to address the information gaps described in this report. Currently, the level of ongoing and proactive interdepartmental collaboration falls short.

In March 2016, the LA County Board of Supervisors formed a multi-agency team to conduct site visits and collect information about safety conditions, permit requirements, and zoning recommendations for oil and gas wells in unincorporated areas of the County. The multi-agency team included officials from the County's Department of Regional Planning, Department of Public Health, Fire Department, and Department of Public Works. LAFD staff expressed concerns about involvement in a similar endeavor for the City. They cautioned that it would reduce efficiency and decrease the likelihood that all required inspections could be completed with existing staff. Further, LAFD officials expressed concerns about the effectiveness of non-LAFD personnel unfamiliar with oil and gas drilling sites accompanying LAFD inspectors. Despite these concerns, the City should evaluate the feasibility of designing a comprehensive monitoring and enforcement program that includes staff across City Departments.

Recommendations

The Petroleum Administrator should:

1.1 Collaborate with DCP/OZA, the City Attorney, LAFD, and DBS to identify high-risk drilling sites and initiate targeted reviews to determine whether operators are in compliance with existing conditions of approval requirements.

1.2 Engage residents and businesses near high-risk drilling sites to document evidence of nuisance operations.

1.3 Collaborate with DCP/OZA to implement modified conditions or corrective actions for those high-risk sites determined not to be in compliance with existing conditions of approval or responsible for nuisance operations. Prioritize modernization of drilling sites by requiring operators to install continuous air monitoring devices and other emerging technologies.

The Los Angeles Fire Department should:

1.4 Prioritize annual Fire Code inspections using additional risk-based factors such as: (1) proximity to residential and other non-industrial sites; (2) age and number of wells; and (3) number and severity of previous Fire Code violations cited by LAFD.

City Policymakers should:

1.5 Amend the LAMC to allow the City to undertake periodic reviews of conditions of approval at all drilling sites to consider public health risks and surrounding land use. Collaborate with the Petroleum Administrator to determine an appropriate interval for these reviews.

1.6 Consider developing an enhanced oversight program to proactively monitor and enforce compliance with conditions of approval at oil and gas drilling sites based on experience and data collected from the targeted reviews. In addition, determine whether annual inspections performed by City Departments such as LAFD and DBS should be incorporated into the proactive monitoring and enforcement program.

SECTION II: PROTECTING CITY TAXPAYERS' FINANCIAL INTERESTS

The State's regulatory framework is designed to protect the public and environment from adverse impacts of oil and gas extraction activities; however, accidents such as blowouts, spills, or contamination are sometimes unavoidable. In addition, irresponsible or insolvent operators may desert wells when they are no longer producing, rather than plug the wells in accordance with State requirements. The probability, timing, duration, and magnitude of these risk events depends on many factors, including the wells' phase of production; proximity to residents or sensitive environmental sites; method of extraction/injection; well depth; age of well; financial stability of the well operator; and effectiveness of regulators.

Aside from potential harm, the financial costs of remediating issues related to oil and gas drilling sites in a densely-populated urban environment can be significant. Given the risks, the City needs to consider appropriate financial coverage requirements to protect taxpayers from well operators that knowingly or unknowingly cause harm.

The City's Risk Management Approach Should Include a Combination of Insurance and Increased Bonding Requirements

The type of financial risk management instruments and required coverage amounts should be determined based on the type of risk the City is seeking to mitigate.

Insurance

The City can initiate legal proceedings to pursue compensation from any operator responsible for an accident that causes harm to public safety or the environment. However, this approach may not be successful in providing funds necessary for remediation because the impacts of a serious incident may render the responsible operator insolvent. In addition, the City would be required to provide the evidence to show an operator was responsible for the accident, and that could prove challenging. One potential strategy is to transfer risk to a third party, through insurance requirements. Because insurers develop policies based on the required coverage amount and level of risk, operators of older drilling sites may be incentivized to invest in site modifications or safety enhancements to drive down monthly insurance costs.

The LAMC does not require operators of drilling sites on private property to maintain insurance policies with the City as a named party.[9] However, DCP/OZA may use its discretion to require well operators to maintain insurance on a case-by-case basis, by attaching the requirement to the conditions of approval. For example, the conditions of approval for the South L.A. drilling site described earlier in this report require the operator to maintain $2 million in general liability insurance to account for potential property damage caused by drilling or extraction activities. The City lacks a database of conditions of approval for all oil and gas drilling sites, therefore, the extent to which other well operators have been subject to similar insurance requirements is unknown.

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[9] The LAAC requires the Risk Manager to recommend changes to the City Council about the adequacy of ordinances that require entities to post insurance. However, the LAAC does not appear to specifically assign responsibility for situations where there is no insurance requirement.

Some local jurisdictions such as Culver City and Simi Valley require all operators of oil and gas wells to maintain general commercial liability insurance. Of particular note is the City of Carson, which made significant revisions to its Municipal Code in 2016. Operators of each oil and gas drilling site in Carson are required to maintain liability policies that also name the City of Carson, its officers, officials, agents, and employees as additional insured entities. The specific insurance requirements are outlined in the table below.

Figure 9: City of Carson Insurance Requirements for Operators of Oil/Gas Wells[10]

Insurance Type	Minimum Requirements	Notes
Control of Well Insurance	$40 million per occurrence Max deductible of $500k per occurrence	Only applies during drilling or reworking. Policies designed to cover cost of controlling well that is out of control, drilling or restoration expenses, and seepage and pollution damage. Requirements may be waived if operations are confined to depths and formations within which there is no substantial risk of loss of well control.
Excess (or umbrella) liability insurance	$25 million	Provides excess coverage for each of the policies listed below, except for underground reservoir (or resources) damage.
Bodily injury and property damage	$2 million per occurrence $2.5 million in the aggregate	Coverage must include premises, operations, blowout or explosion, underground property damage, underground reservoir (or resources) damage, etc.
Environmental impairment (or seepage and pollution) coverage	$2 million per occurrence $2.5 million in the aggregate	Covers sudden or accidental release of oil/gas, vapors, fumes, chemicals, etc. Must be included in general liability coverage or as separate coverage. The policy must include a minimum 10 year discovery period.
Commercial automobile liability insurance	$1 million per occurrence	Shall include coverage for all owned, hired and non-owned automobiles, or other licensed vehicles.
Workers' Compensation Insurance	$1 million per occurrence	Operators must maintain coverage in accordance with minimum statutory requirements.

There are a variety of indemnity agreements and insurance models that may be appropriate. For example, the City can require well operators to obtain a policy that names the City as an

[10] According to Carson's Municipal Code, well operators can "self-insure if insurance is not commercially feasible to obtain and maintain in the commercial insurance market, as certified by a written report prepared by an independent insurance advisory of recognized national standing…" This exception only applies to excess (or umbrella) liability coverage, control of well insurance, and environmental impairment (or seepage and pollution) coverage.

additional insured entity, which would allow the City to file a claim in the event that the activities of well operator harm the City's financial interests.

City Policymakers should consult with the Risk Manager and Petroleum Administrator and consider the following issues while developing insurance requirements: (1) policy types and minimum coverage amounts; (2) whether the City's interests would be best protected by being included in the policy as an additional insured entity; (3) duration of environmental insurance requirements to account for long-term risks such as oil seepage after a well has been plugged and abandoned; (4) carefully written language to ensure the City is able to collect from the insurance company in the event of a claim being filed; and (5) the minimum credit rating (as determined by a generally accepted rating organization) for eligible insurers.

Surety Bonds

In the absence of insurance requirements, the City requires two sets of surety bonds related to oil and gas well operations: a zoning bond and an operational bond. These surety bond requirements do not absolve well operators from liability associated with fire, well failures, or conditional use violations. Generally, the system is designed to protect the City and its taxpayers from irresponsible operators who simply desert wells when they are no longer productive or insolvent operators who enter bankruptcy and cannot afford the costs of well plugging and abandonment. Given the anticipated costs, surety bond requirements should reflect the costs of reclaiming a site on public or private land.

The LAMC requires well operators to post a $5,000 bond or deposit cash when applying for a permit to drill, operate, or maintain any oil or gas well ("zoning bond") in urbanized areas of the City or the Los Angeles City Oil Field Area. The bond is intended to ensure operators comply with conditions of approval established by DCP/OZA. If the operator fails to comply, the City can claim the cash deposit or obtain financial compensation from the surety company and use the funds to defray any costs incurred to ensure compliance with zoning requirements and conditions of approval. Zoning bonds are required to be maintained throughout the life of an established drilling district or well. DCP/OZA staff stated the bond requirements were inadequate and noted that the last drilling district in the City was created decades ago.

The City's Fire Code, which is part of the LAMC, also requires operators of oil and gas wells to post surety bonds of $10,000 per well, or through a blanket bond of $50,000 for any number of wells ("operational bond"). The primary purpose of the operational bond is to ensure that the City has financial resources available in the event that an operator fails to plug and abandon a well in accordance with State law or is found in violation of fire and safety requirements outlined in the City's Fire Code. Bonds can be obtained from a surety company or the operator can deposit cash with the City Treasurer in-lieu of posting a bond. Operational bonds are released when the operator plugs (i.e., caps and seals the well in accordance with DOGGR requirements) and abandons (i.e., removes all equipment and restores the site back to its original condition) the well. The LAMC section related to operational surety bond requirements has not been revised for decades; City officials agreed that the requirements were outdated. According to the LAAC, the Risk Manager is required to make a recommendation to the City Council if it is determined that the City's bonding requirements do not provide adequate protection.

Several neighboring municipalities have lower operational surety bond requirements than the City, but require additional proof of liability insurance to operate a well within their respective jurisdiction. In addition, jurisdictions such as Culver City, Santa Fe Springs, and Carson have provisions in place to determine the appropriate level of bonding that is needed on a case-by-case basis. The City of Carson requires its Petroleum Administrator to reassess each bond requirement every five years to determine whether the amount is sufficient to cover any abandonment or remediation costs.

Figure 10: Comparison of Oil and Gas Well Bonding and Insurance Requirements for Selected Neighboring Municipalities

	Bonding Requirements		Insurance Requirements		
Jurisdiction	**Individual Well**	**Multiple Wells (5 or more)**	**Liability**	**Property**	**Notes**
City of Los Angeles	$10,000	$50,000	N/A	N/A	$50,000 blanket bond for any number of wells
City of Simi Valley	$10,000	N/A	$500,000/$1,000,000	$2,000,000	Liability limits for one person/all persons
Culver City	①	①	$10,000,000	N/A	General Commercial Liability
City of El Segundo	$2,000	$10,000	N/A	N/A	
Santa Fe Springs	②	②	N/A	N/A	
City of Torrance	$5,000	$25,000	N/A	N/A	
City of Fullerton	$2,000	$10,000	N/A	N/A	
City of Carson	③	③	$2,000,000	See note	Environmental $2M / WC $1M / Auto $1M / Umbrella $25M
County of Los Angeles	$2,000	$10,000	N/A	N/A	

① Bond requirements did not have a set amount, bond shall guarantee the faithful performance of all the conditions of the permit, and all other pertinent City, State or Federal laws rules and regulations.

② Bond requirements did not have a set amount, bond shall guarantee the faithful performance, sum to be determined by resolution of the City Council or State law, for each well.

③ The Petroleum Administrator shall determine the amount of the bond based on many factors and to ensure the completion of abandonment to the amount not covered by DOGGR bonds. Bond shall be inflation indexed, reassessed every 5 years, etc.

In contrast, the City has established minimum bonding requirements without requiring additional liability insurance, nor a process to adjust for risk factors unique to each site such as well depth, methods of operation, operator history, and proximity of the well to residents and sensitive environmental sites.

As the regulator of oil and gas drilling activities throughout the State of California, DOGGR also requires operators to file bonds when seeking to drill, re-drill, deepen, or maintain an oil well. The conditions of bonds filed with DOGGR are tied to compliance with all provisions of Division 3 of the State's Public Resources Code and lawful orders made by DOGGR officials. DOGGR modified its bond requirements in January 2018. The tables below compare current individual and blanket bond amounts required by the City and DOGGR.

Figure 11: Bonding Requirements for Individual Oil and Gas Wells in the City

Jurisdiction	Individual Well	Well Depth	Number of Wells
City of Los Angeles	$10,000	N/A	Unlimited
DOGGR	$25,000	< 10,000 feet deep	1 to 19
DOGGR	$40,000	> 10,000 feet deep	1 to 19

Figure 12: Bonding Requirements for Multiple Oil and Gas Wells in the City

Jurisdiction	Blanket Bond Amount	Well Depth	Number of Wells
City of Los Angeles	$50,000	N/A	Unlimited
DOGGR	$200,000	N/A	20 to 50
DOGGR	$400,000	N/A	51 to 500
DOGGR	$2,000,000	N/A	501 to 10,000
DOGGR	$3,000,000	N/A	More than 10,000

The underlying goal of requiring a surety bond for oil and gas wells is to protect taxpayers from absorbing the cost of remediating a site if an operator is unable to pay. For example, idle oil and gas wells that are no longer in operation present environmental and safety risks. Irresponsible operators may shirk their responsibility to properly plug and abandon these wells in accordance with State law, because the costs can be significant and there is no return on investment. If DOGGR cannot identify the operator of a deserted well, or an operator enters bankruptcy, DOGGR can access funds from its Oil and Gas Environmental Remediation Account to plug and therefore appropriately abandon those "orphan" wells that pose a danger to life, health, water quality, wildlife, or natural resources. The State has gradually increased the maximum funding level for this account and DOGGR is currently authorized to spend up to $3 million[11] per year to remediate deserted wells. DOGGR reportedly has plugged approximately 1,350 deserted wells since 1977 at a cost of more than $27 million (approximately $20,000 per well).

Although the State has a program in place to cover costs associated with orphan wells that pose a threat to public safety and the environment, it has recently taken steps to enhance its oversight. In September 2016, Governor Brown signed a bill to reduce the number of idle wells that may become orphaned. All operators must either submit a plan for the management and elimination of all long-term idle wells, or pay an annual fee. By increasing fees required to maintain idle wells, DOGGR's goal is to encourage operators to either reactivate or plug and appropriately abandon idle wells in conformance with State requirements.

DOGGR's remediation budget and bond requirements may not be sufficient to cover costs associated with all orphan wells in the City of Los Angeles. DOGGR recently sealed two orphan wells buried under a residential street in an Echo Park neighborhood after receiving complaints

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[11] Commencing on July 1, 2018.

from residents about foul odors from leaking gas. The wells were originally drilled before 1903, and DOGGR concluded that they would likely continue to deteriorate without intervention. The total cost of plugging the two wells exceeded $2 million. The City could have been forced to absorb a portion of the cost if DOGGR did not have funds available, or if deserted wells in other areas of the State were a higher priority. This example, though seen as a worst-case scenario, demonstrates the need for financial assurance requirements to reasonably reflect the cost of remediation.

The City Needs to Ensure Well Operators Maintain Active Insurance and Bond Coverage

Once a well operator provides proof of insurance or bond coverage, the City should have effective administrative processes in place to ensure that the insurance policy or surety bond does not lapse.

Insurance

As the City develops insurance requirements for oil and gas well operators, it should develop minimum notification requirements about insurance policy renewals, revisions, and cancellations. Failure to maintain coverage should be grounds for cancellation or suspension of the annual operational permit issued by LAFD, until the operator provides proof of coverage.

Surety Bonds

Each active and idle well in the City should be covered by an individual or blanket bond. Once a surety bond has been posted, it is incumbent upon the City to periodically confirm that it is still valid and the surety company is in good financial standing and can provide funds if a claim is filed. The LAAC tasks multiple City Departments with responsibilities related to oversight of surety bonds once they have been filed:

- City Departments that receive bonds are required to "keep an adequate" record of details associated with each bond such as filing date, operator performance, and occurrence of any loss or default;
- the Risk Manager is required to maintain bonds "in such manner as to keep them enforceable";
- the City Controller, upon the Risk Manager's request, is required to report on the financial standing and responsibility of a surety company that has offered a bond to the City.

The LAMC requires operators to file operational bonds or submit cash-in-lieu deposits to the Office of Finance when submitting an application to drill, operate, or maintain a well. We requested an inventory of surety bonds for oil and gas wells but Finance staff could not produce a listing; however, Finance provided a list of eight cash-in-lieu deposits, totaling approximately $225,000.

The LAMC requires operators to file zoning bonds with DCP/OZA when submitting applications to establish drilling districts or sites. DCP/OZA staff were unfamiliar with the status and location of zoning bonds filed by oil and gas well operators because zoning bonds must be submitted with applications to establish drilling districts or sites, neither of which has occurred in recent years.

DCP/OZA staff stated that they inherited oversight of the zoning bonds and were generally unaware of their existence until a surety company contacted them in November 2016 and requested to cancel an operator's bond.

We also obtained information from the CAO Risk Management Division's Track4LA system related to oil and gas bonds. Track4LA showed only 70 records (some of which were blanket bonds or cash deposits covering multiple wells) related to oil well surety bonds or cash-in-lieu deposits, however, all of these records were created after 2005. According to CAO Risk Management staff, no records for oil and gas bonds transacted prior to 2005 were migrated into the Track4LA system, and they had no other information regarding the existence or completeness of such records.

Because City Departments have not effectively maintained and monitored surety bonds and many of the drilling sites were established decades ago, it is possible that older wells are no longer covered by active bonds due to insolvent surety companies. While the existing bond requirements appear to be inadequate and should be revisited, the City must also determine the status of its existing bond inventory, and determine how to bring operators into compliance. Rather than allocating resources to search for old, and perhaps expired or invalid, paper-based bond documents in the City Archives or Departmental files, the City should require operators to provide proof of active bond coverage on an annual basis.

Recommendations

City Policymakers should:

2.1 Amend the LAMC to require all operators of oil and gas drilling sites to maintain insurance coverage. Consult with the Risk Manager and Petroleum Administrator to determine appropriate types of insurance coverage and minimum coverage requirements.

2.2 Amend the LAMC to revise the surety bond amounts required from operators of oil & gas wells to reflect risk, including providing the Petroleum Administrator with discretionary authority to set bond amounts on a case-by-case basis and allow for periodic reassessments to account for changing conditions.

2.3 Revise City practices to require operators of all active and idle wells to submit proof of active and adequate bond coverage as well as liability insurance as part of the application process to obtain or renew an LAFD operational permit.

2.4 Direct LAFD to submit/upload all bond and insurance documents to the system maintained by the CAO's Risk Management Division.

The Petroleum Administrator should:

2.5 Work with the CAO Risk Management Division and DCP/OZA to periodically review the status of all oil and gas well surety bonds and insurance policies on file with the City. For operators and/or sites lacking the required and valid surety bond or insurance coverage, consult with the City Attorney to evaluate options for resolution.

2.6 Work with responsible City Departments to file claims on surety bonds or insurance policies when drilling site operators demonstrate a pattern of noncompliance with legal requirements and conditions of approval.

SECTION III: GENERATING CITY REVENUE FROM OIL AND GAS WELLS

The City can also exercise local control over oil and gas wells through imposition of taxes, fees, and other industry-specific revenue generation strategies. Given the historical nature of drilling activity in the City, successful extraction of oil/gas from older wells is likely more challenging and expensive than in the past. Policymakers should consider these factors when evaluating taxes and fees from oil/gas extraction activity and develop an equitable framework that generates revenue for the City without discouraging business activity.

Taxes Applicable to All Businesses in the City

Operators of oil and gas drilling sites are subject to several types of State and local government taxes like other businesses operating within the City. As shown in the table below, the City's business (i.e., gross receipts) tax and electricity user tax are the only tax revenue streams that are imposed and collected directly by the City. Other forms of tax revenue originating from oil and gas activities are collected by other entities, and the City receives an allocation or apportionment of that revenue.

Figure 13: Taxes Applicable to All Businesses in the City

Type	Rate	Tax base	Responsible entities
Property tax	City Treasury receives approximately 25% distribution from 1% property tax rate levied on properties in LA	Market value of an oil/gas mineral property interest determined by estimated value of proved reserves which are likely to be recoverable in the future	• LA County Assessor • LA County Auditor-Collector • LA County Treasurer and Tax Collector
Utility user taxes	Gas: 10% Electricity: 12.5% (industrial rate) Communications: 9%	Assessed upon monthly service charges	• LA Department of Water and Power • Southern California Gas Company • Communication service providers
Business tax	$1.01 per $1,000 of gross receipts	Each business transaction that occurs between entities (with separate business interests) is subject to taxes on the revenues generated from wholesale sales	• Office of Finance
Uniform local sales and use taxes	City Treasury receives 1% distribution from statewide sales/use tax rate of 7.25%	Sales - all retailers subject to sales tax in exchange for privilege of selling tangible goods at retail Use - buyers who engage in the use, storage, or other consumption of tangible personal property are subject to tax if retailer did not collect on behalf of State/City	• California State Board of Equalization

The amount of taxes collected from oil and gas operators cannot be readily determined; the City does not have a mechanism to actively track how much tax revenue it receives in the aggregate from operators of oil and gas wells. Revenues generated from these taxes are deposited into the City Treasury.

Industry-specific Fees, Taxes, and Royalties

The City can also impose industry-specific fees to recover local regulatory costs, taxes, or royalties to generate revenue. Various strategies to recover costs and generate revenue are outlined below.

Local Regulatory Fees

Although the City cannot levy taxes without voter approval, local governments in California are authorized to impose regulatory fees related to:

- issuing licenses and permits;
- performing investigations, inspections, and audits; and
- administrative enforcement and adjudication.

According to the California State Constitution, "the local government bears the burden of proving by a preponderance of the evidence that a levy, charge, or other exaction is not a tax, that the amount is no more than necessary to cover the reasonable costs of the governmental activity…"

The City Should Prioritize Cost Recovery as it Develops an Enhanced Local Oversight Framework

The City's primary tool for recovering regulatory costs associated with active and idle wells are through fees for LAFD operational permits and specific-action permits.[12] The costs for these permits range from $1,000 to $2,600. Local jurisdictions with large numbers of active and idle wells also charge operators regulatory fees to recover the costs of issuing permits and performing public safety inspections. Although the specific activities performed as part of the inspection may vary, we noted the fees charged by other local jurisdictions (such as LA County, Long Beach, and Culver City) are lower than those currently charged by the City.

The City does not currently have legal authority to recover costs associated with the enhanced local oversight framework envisioned by the recent City Council motion. As a result, costs to perform activities such as conditional use inspections and administrative reviews of permits issued by external regulatory entities would be borne by the City's taxpayers through an allocation of the City's discretionary funds, rather than operators of drilling sites. In contrast, the City of Carson recently revised its Municipal Code to allow full cost recovery for activities related to enhanced compliance monitoring and periodic reviews of oil and gas drilling sites.

Extraction (i.e., "barrel") Taxes

The LAMC previously included a tax specifically designed to generate revenue from operators of oil wells located in the City. On a quarterly basis, well operators were required to pay $21.29 for each well that produced 200 barrels of oil or less. Wells that produced more than 200 barrels of

[12] The City is also authorized to recover all direct and indirect costs associated with performing inspections to ensure compliance with statewide standards to each facility in its jurisdiction that treats or generates hazardous waste, operates underground storage tanks, or stores hazardous material.

oil were subject to the base fee ($21.29) plus $0.11 for each barrel of oil extracted during the reporting period. This section of the LAMC was repealed in 1996, and taxes on oil production were shifted to the business tax on wholesale sales described in Figure 13.

The City cannot unilaterally undo its repeal of the barrel tax or implement another tax on oil extraction; local governments in California must obtain voter approval to levy any new tax. In March 2011, a ballot measure proposed that the City would impose a tax of $1.44 per barrel of oil extracted within the City. The proposed tax rate was significantly higher than barrel taxes imposed by neighboring jurisdictions. The proposed ballot measure was narrowly rejected by voters 51.07% to 48.93%.

The City Should Consider Reintroducing a Barrel Tax for Voter Approval

Although the March 2011 ballot measure was narrowly rejected, increased awareness about the impacts of oil and gas extraction in a densely populated environment combined with high profile incidents such as Aliso Canyon may have shifted voter opinion.

Currently, barrel taxes in neighboring jurisdictions such as Long Beach, Santa Fe Springs, and Seal Beach range from $0.41 to $0.49 per barrel. Based on the Petroleum Administrator's estimate of current production levels (7,500 barrels per day), a barrel tax of $0.50 would generate approximately $1.4 million each year. City Policymakers should perform a formal cost-benefit analysis that considers factors such as:

- projected extraction volume based on historical records and the likelihood of future drilling activity;
- cost of placing the measure on the ballot;
- ongoing administrative costs associated with imposing and collecting the tax; and
- an appropriate tax rate.

If the City decides to move forward with a ballot initiative, City Policymakers should determine whether revenue generated from these taxes should be deposited in the City's general fund or restricted to a specific purpose.

Revenues from Oil and Gas extracted from Subsurface City-owned Property and Mineral Rights

The City owns a large real estate portfolio (almost 9,000 distinct parcels) that includes parks, libraries, municipal facilities, buildings, and vacant land. The value of the City's properties is not limited to structures that can be built upon them; recoverable deposits of oil and gas may be found in subsurface locations beneath these parcels. The City's ability to generate revenue by using its real estate assets for oil and gas extraction activity depends on the extent to which it owns the mineral rights associated with subsurface parcels of land.[13]

[13] There are various degrees of land ownership in the United States. In a "fee simple" arrangement, the property owner has sole ownership of the surface of the land and sole ownership of any minerals located beneath the surface of the land (i.e., mineral rights or mineral interests). Property owners can also separate (or sever) ownership of the parcel into two distinct components, a surface estate and a mineral estate. Like other property rights, either of these components can be bought, sold, leased, and transferred in accordance with federal and state law.

The scenarios below describe two common business arrangements that can be used to generate revenue from oil and gas extraction activity.

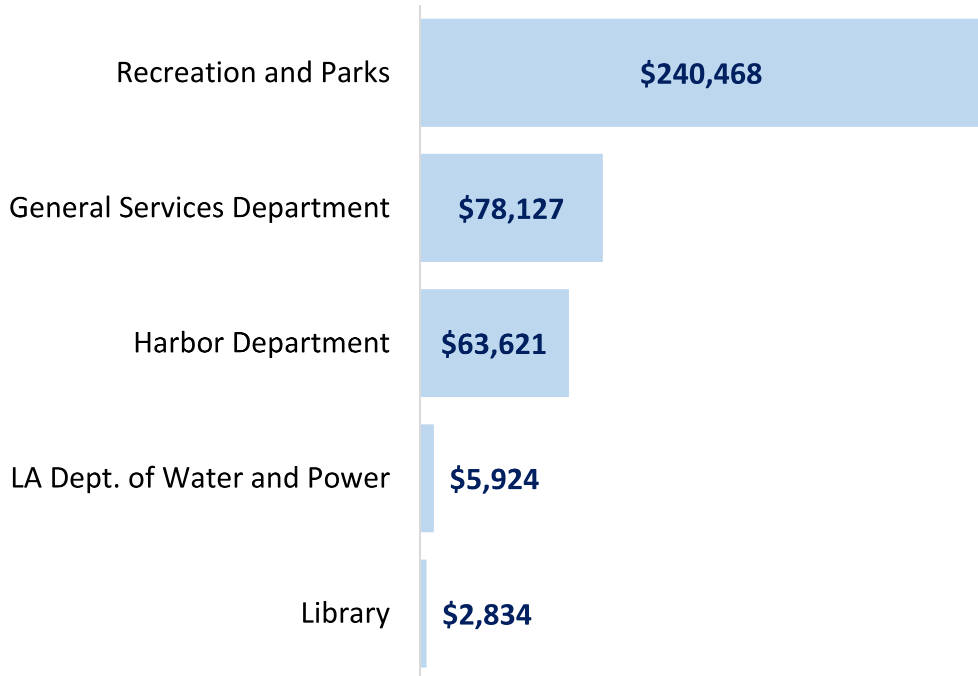
- Scenario 1 – Subsurface deposits of oil and gas often cross property boundaries, including those owned by the City. To facilitate orderly/efficient extraction, the City may enter into pooling or unitization agreements where the City's mineral interests are joined with the mineral interests of other property owners. Together, the owners of the mineral rights delegate their right to drill and extract oil and gas to one or more well operators. In this scenario, the City and other mineral rights owners are paid royalties based on how much oil or gas is removed from subsurface areas, allocated to parcels they own.

- Scenario 2 – The City may enter into lease agreements with private well operators to allow for the construction of a drilling site on City-owned property, which extracts oil and gas from subsurface parcel(s). In exchange for allowing the lessee to operate the drilling site, the City is paid royalties based on how much oil or gas is extracted from subsurface parcels whose mineral rights are owned by the City.[14]

In both of these scenarios, the City's ability to collect the revenue it is owed requires complete information about its mineral interests and related lease and/or unitization agreements. According to information provided by Council-controlled and Proprietary Departments, the City received approximately $390,000 royalty revenue through these methods during FY2017.

[14] Adjacent property owners with mineral rights may also receive royalty payments from the well operator through a pooling or unitization agreement.

Figure 14: City Oil and Gas Royalties (FY2017)



The City Needs to Improve Oversight of Oil and Gas Extracted from City-owned Property to Ensure it Receives the Revenue it is Due

Like any other property owner, the City needs to ensure that its business partners make accurate payments in a timely manner. The LAAC outlines a centralized role for the Board of Public Works/Petroleum Administrator to oversee oil/gas extraction from City-owned property; however, the historical nature of drilling activity in the City combined with a decentralized approach created information gaps that prevented effective oversight.

The City does not currently know the locations of all subsurface parcels where it owns mineral rights. This prevents the ability to identify pooling or unit agreements that include the properties that should generate royalty revenue for the City based on the amount of oil or gas that is/was extracted. According to the Petroleum Administrator, there may be opportunities to recover revenues from former well operators who may not have paid royalties to the City for decades. However, any potential recovery of these funds is not possible without extensive title research of land records, to identify subsurface locations of oil deposits along with parcels owned by the City. Once identified, these parcel numbers can be compared to existing pooling and unit agreements, as well as historical extraction data, which is maintained by DOGGR.

During our review, staff from some of the City Departments listed in Figure 14 acknowledged that they did not have effective processes in place to ensure the City was receiving all of the revenue it was owed. For example:

- RAP staff could not verify the accuracy of all of the royalty payments it received;

- GSD and LADWP staff stated that they received royalty payments, but were unsuccessful in efforts to obtain information from well operators about the sources of those payments; and
- Harbor staff were aware that property under their control was part of a unitization agreement, however, they did not have a copy of the agreement or a process to verify if the royalty payments were accurate.

These examples demonstrate that City Departments are not exercising sufficient control to ensure the City receive the appropriate revenue for a defined use of the City's property assets.

The City Needs to Verify that Former Lease Operators Have Restored Public Property to its Original Condition

Lessees who construct and operate drilling sites on City-owned property are required to plug and abandon the wells in accordance with DOGGR requirements and restore the site back to its natural condition. Given the lack of effective oversight, the historical nature of the leases, and the long-term absence of a full-time Petroleum Administrator to provide technical assistance and coordinate activities, it is especially imperative for the City to ensure its former lessees have fulfilled their obligations.

One of the leases we reviewed included provisions to protect the City from financial risks associated with deserted wells on public property. RAP's lease with an operator at Rancho Park included provisions intended to protect the City if the operator deserted the well(s) or entered into bankruptcy. The lease extension was signed in 1994 and required the operator to make annual cash payments of $50,000 until the City received $500,000 to be held in a Trust Fund. RAP is authorized to periodically review the Fund balance and increase the requirement based on the estimated cost of well abandonment and site restoration. Upon the operator's fulfillment of all restoration requirements, the funds would be returned to the lessee.

Given the lack of reliable information about oil and gas leases, the City cannot make informed decisions about whether it should continue to lease public property for oil and gas exploration. Policymakers must weigh the costs of effectively administering the leases and the inherent environmental and public safety risks, against the amount of revenue that is generated. If the City continues to award and administer leases, it needs to improve oversight.

Recommendations

City Policymakers should:

3.1 Amend the LAMC to allow the City to recover costs associated with enhanced oversight activities including: (1) issuing licenses and permits; (2) performing investigations, inspections, and audits; and (3) administrative enforcement and adjudication of oil and gas wells.

3.2 Perform a cost-benefit analysis to explore the feasibility of reintroducing a barrel tax for voter approval. At minimum, the cost-benefit analysis should consider: (1) projected extraction volume based on historical records and the likelihood of

future drilling activity in the City; (2) cost of placing the measure on the ballot; (3) ongoing administrative costs associated with imposing and collecting the tax; and an appropriate per-barrel tax rate.

3.3 Direct all Departments to verify any oil or gas exploration on or under the real property they control. Once an inventory has been developed, determine whether to renew and renegotiate any expired lease agreements.

3.4 Formally transfer the responsibility for oversight of oil and gas extracted from City-owned properties to the Petroleum Administrator.

3.5 For future lease agreements, consider adding terms that would require payments into a restoration/abandonment fund, modeled after the Rancho Park lease.

The Petroleum Administrator should:

3.6 Perform title research to identify subsurface parcels whose mineral rights are owned by the City. For those related to oil fields with extraction activity, determine whether the City received appropriate royalty payments. For well operators who did not pay the City royalties it was owed, consult with the City Attorney to explore legal options.

3.7 Collaborate with LAFD and DOGGR to determine whether former lessees fulfilled their obligations to plug and abandon wells in accordance with State law, and restore the site to its natural condition.

3.8 For lessees who did not fulfill their obligations to plug and abandon wells in accordance with DOGGR requirements, consult with the City Attorney to explore legal options, and propose any remedial actions that should be taken by the City.

3.9 Develop and implement an improved reporting process to provide assurance of compliance with extraction agreements with well operators, including periodic reviews of royalty payments.

SECTION IV: INCREASING TRANSPARENCY AND INFORMATION SHARING

A comprehensive and reliable source of information related to oil and gas drilling sites is essential for City officials to make data-driven policy and operational decisions in a timely manner. We identified opportunities where the City could improve its management of information to facilitate the development of an efficient and effective centralized oversight framework.

The City's Management of Information Related to Oil and Gas Drilling Sites Requires Significant Improvement

The LAAC tasks the Petroleum Administrator with coordinating "all matters respecting or concerning the exploration for or production of petroleum within this City." To effectively perform this task, the Petroleum Administrator needs easy access to reliable information about the drilling site and the activities of City Departments and external agencies tasked with overseeing the site.

City Departments are responsible for a wide range of activities related to oil and gas drilling sites. Because the City did not have a full-time Petroleum Administrator in place for decades, these activities have been performed independently rather than as part of a centralized oversight framework. This fragmented approach resulted in the development of information silos within individual City Departments.

External entities such as DOGGR and SCAQMD are responsible for regulating oil and gas drilling sites through an oversight framework that includes permitting, inspections, and ongoing monitoring to enforce compliance with federal and State regulatory requirements. Access to information about these activities allows the City and Petroleum Administrator to identify public health and environmental risks as they emerge and before they balloon into larger problems.

During our review, we identified several examples that indicate the City needs to improve its approach to managing information related to oil and gas drilling sites.

Inventory of Well Locations and Production Data

Some of the third-party data relied upon by the City may not adequately meet its operational needs. Although DOGGR maintains an online database with an inventory of all known active, idle, abandoned, and buried wells, the reliability of the data has not been verified by the City. DOGGR's database includes information such as unique identification numbers for each well in accordance with standards established by the American Petroleum Institute (i.e., API number), well status, well operator information, oil/gas field names, county names, and GPS coordinates; but the database does not include the ***city*** in which the well is located. Because oil/gas fields can cross city/county jurisdictions, the ability to isolate wells located in the City of Los Angeles requires a custom extract generated by DOGGR. Multiple City officials expressed concerns about the accuracy of the well locations on DOGGR's maps and cautioned about the potential impact of inaccurate data and previously unknown well sites interfering with new construction projects initiated by developers.

Because LAFD is tasked with conducting inspections and issuing permits to ensure compliance with the City's Fire Code, it maintains its own inventory of oil and gas wells separate from the DOGGR inventory. The list maintained by LAFD includes more than 3,500 wells. Although LAFD categorizes wells differently than DOGGR, there are significant discrepancies in the number of total wells and the number of inactive wells (i.e., plugged/abandoned or buried) compared to the data provided by DOGGR, as noted below.[15]

Figure 15: LAFD and DOGGR Well Inventory

Source of Inventory	Wells Identified	Active and Idle Wells	Inactive Wells (Plugged & Abandoned or Buried)
LAFD (Sept. 2017)	3,558	1,139	2,419
DOGGR (April 2018)	5,130	1,067	4,063
Difference	***1,572***	***72***	***1,644***

These discrepancies indicate that there are approximately 1,600 buried, or plugged and abandoned wells that LAFD may not be aware of. Buried or improperly plugged wells may leak methane. The LAMC does not require LAFD to inspect wells once they have been appropriately plugged and abandoned; however, LAFD and DBS have a role in implementing the City's methane mitigation requirements. The City's ability to verify the accuracy of its well inventory has been limited; until 2017 the LAFD list included 4-digit numbers assigned to each well, but did not include API numbers used in the DOGGR list. LAFD staff has begun the process of reconciling the well inventory data.

In addition to challenges regarding well inventory and locations, the City does not actively track how much oil or gas is extracted from wells located within the City. Operators are required to submit monthly production reports to DOGGR that are uploaded to their online system; however, the City does not currently have a process or method to pull that data and track it in the aggregate. The Petroleum Administrator estimated that 7,500 barrels of oil are extracted on a daily basis in the City, though the amount likely fluctuates. The City's ability to make informed policy and operational decisions about oil and gas extraction is limited if it cannot monitor the volume of activity on an ongoing basis.

Conditions of Approval for Oil and Gas Drilling Sites

The City does not have an electronic database of operating requirements for all oil and gas drilling sites. According to DCP/OZA personnel, letters outlining conditions of approval may be available through various DCP systems (Planning Case Tracking Management System and/or Zoning Information and Map Access System). However, the availability of documents depends on the date the site was established or last modified; hard copy documents associated with older drilling sites are stored in the City Archives. A large number of drilling sites are likely to fall into this category, given the historic nature of oil and gas activity in the City.

In an April 2016 report prepared by the Chief Legislative Analyst and City Administrative Officer, DCP/OZA outlined the need to catalog and digitize existing conditions of approval; but this has

[15] According to LAFD staff, their inventory of 'active' wells includes idle wells, since both active and idle wells require annual Fire Code inspections. The DOGGR data in Figure 15 was reorganized to match LAFD's criteria.

not yet occurred. Lacking a comprehensive electronic repository inhibits DCP/OZA's ability to effectively work with the Petroleum Administrator and proactively identify drilling sites with potential for new or modified conditions. In addition, DBS cannot effectively carry out its responsibility to enforce DCP/OZA's land use decisions without reliable access to the conditions of approval for each drilling site.

External Regulatory Entities

The LAMC does not require operators or external regulatory agencies to notify the Petroleum Administrator when permits are issued, operators are cited for violations, or complaints are received. Currently, the Petroleum Administrator must engage DOGGR and other external agencies on a case-by-case basis. The Petroleum Administrator recently reached an agreement with SCAQMD to receive email notifications when operators are cited for violations pertaining to air pollution.

The examples below demonstrate the importance of timely access to information maintained by external regulatory entities.

- The City recently alleged that an operator performed at least 42 different re-drilling and maintenance activities with DOGGR's permission over a 16-year period without submitting an application to DCP/OZA in accordance with LAMC requirements. If the City had been notified, it could have considered implementing new conditions to ensure the activities were performed in a manner that were not a nuisance to the surrounding community.
- From 2010 to 2013, SCAQMD received approximately 260 complaints about poor air quality and effects such as headaches and nosebleeds from residents living near a drilling site. DBS officials tasked with enforcing conditions at the site were not aware of those complaints submitted or investigated by SCAQMD.

Although these examples may be outliers and the result of not having a full-time Petroleum Administrator in place to facilitate coordination, they highlight information gaps that need to be addressed by the City.

A Way Forward

The success of the Petroleum Administrator's efforts to coordinate the activities of City Departments and monitor the actions of external regulatory agencies depends on the ability to access reliable information about oil and gas drilling sites in a timely manner. Moving forward, the City needs to <u>compile</u> the necessary information and then <u>connect</u> it in a manner to facilitate effective decision making.

As the City builds a centralized and reliable repository of information, it should also prioritize development of a public-facing website to increase transparency and facilitate public engagement on issues related to oil and gas drilling sites. At minimum, the website should include information about well locations, permits, extraction amounts, conditions of approval, regulatory violations, and a complaint-intake mechanism. This should be supplemented by improved public outreach through City Council offices, Neighborhood Councils, and community-based organizations to engage residents, especially those who may be less technologically-inclined. Ultimately, the City's goal should be to educate and empower residents to provide input on matters that affect their safety, health, and quality of life.

Recommendations

The Petroleum Administrator should:

4.1 Collaborate with responsible City Departments to develop short- and medium-term plans to identify and compile relevant records that are currently located in the City Archives or maintained by City Departments.

4.2 Consult the City Attorney to establish formal information sharing agreements with external regulatory entities.

4.3 Collaborate with responsible City Departments to determine whether existing technology platforms can be used to develop a centralized database of oil and gas drilling sites and relevant information. If not, the Petroleum Administrator should identify reasonable, cost-effective alternatives.

4.4 Develop a public-facing website to increase transparency and facilitate public engagement on issues related to oil and gas drilling sites.

City Policymakers should:

4.5 Consider revising the LAMC to require operators of drilling sites to notify the Petroleum Administrator of communications submitted to and received from external regulatory agencies. City officials should consult with the Petroleum Administrator to identify sources and types of information to be reported. At minimum, the notification requirement should include a timeframe within which the information must be provided.

4.6 Consider revising the LAMC to require oil and gas operators to notify the Petroleum Administrator when complaints are received. At minimum, the notification requirement should include a timeframe within which complaints should be forwarded to the Petroleum Administrator.

SCOPE & METHODOLOGY

The objective of our review was to identify areas of opportunity where the City can improve its oversight of oil and gas drilling sites as it moves toward developing a modern and centralized framework.

We planned and performed the review to obtain sufficient, appropriate evidence to provide a reasonable basis for our observations and conclusions based on our objectives. Fieldwork was primarily conducted from September 2017 through January 2018.

In accordance with auditing standards and best practices, we conducted interviews and walkthroughs of processes, reviewed documents and performed benchmarking, as noted below:

Interviews and Walk-Throughs
We conducted multiple interviews with the Petroleum Administrator and representatives from other City Departments to assess current roles and responsibilities and to document the quality and extent of interdepartmental and interagency collaboration, and to gain perspective on areas of potential improvement in developing a centralized oversight framework.

Data Analysis and Documents Reviewed
Where available, we gathered and reviewed documentation on the activities of City Departments tasked with responsibilities related to oil and gas drilling sites. We reviewed the legal frameworks of State and local laws to determine the extent of the City's authority and evaluate whether it was effectively exercising that authority.

Benchmarking
We researched policies and processes in other municipalities to identify model practices the City should consider as it seeks to improve oversight of oil and gas drilling sites.

SUMMARY OF RECOMMENDATIONS

Recommendation		Pg #	Responsibility Entity	Priority
I.	**IMPROVING QUALITY OF LIFE AND PUBLIC SAFETY**			
1.1	Collaborate with DCP/OZA, the City Attorney, LAFD, and DBS to identify high-risk drilling sites and initiate targeted reviews to determine whether operators are in compliance with existing conditions of approval.	16	Petroleum Administrator	A
1.2	Engage residents and businesses near high-risk drilling sites to document evidence of nuisance operations.	16	Petroleum Administrator	A
1.3	Collaborate with DCP/OZA to implement modified conditions or corrective actions for those high-risk sites determined not to be in compliance with existing conditions of approval or responsible for nuisance operations. Prioritize modernization of drilling sites by requiring operators to install continuous air monitoring devices and other emerging technologies.	16	Petroleum Administrator	A
1.4	Prioritize annual Fire Code inspections using additional risk-based criteria such as: (1) proximity to residential and other non-industrial sites; (2) age and number of wells; and (3) number and severity of previous Fire Code inspections cited by LAFD.	16	Los Angeles Fire Department	A
1.5	Amend the LAMC to allow the City to undertake periodic reviews of conditions of approval at all drilling sites to consider public health risks and surrounding land use. Collaborate with the Petroleum Administrator to determine an appropriate interval for these reviews.	17	Policymakers	B

1.6 Consider developing an enhanced oversight program to proactively monitor and enforce compliance with conditions of approval at oil and gas drilling sites based on experience and data collected from the targeted reviews. In addition, determine whether annual inspections performed by City Departments such as LAFD and DBS should be incorporated into the proactive monitoring and enforcement program.	17	Policymakers	B
II. PROTECTING CITY TAXPAYERS' FINANCIAL INTERESTS			
2.1 Amend the LAMC to require all operators of oil and gas drilling sites to maintain insurance coverage. Consult with the Risk Manager and Petroleum Administrator to determine appropriate types of insurance coverage and minimum coverage requirements.	24	Policymakers	A
2.2 Amend the LAMC to revise the surety bond amounts required from operators of oil & gas wells to reflect risk, including providing the Petroleum Administrator with discretionary authority to set bond amounts on a case-by-case basis, and allow for periodic reassessments to account for changing conditions.	24	Policymakers	A
2.3 Revise City practices to require operators of all active and idle wells to submit proof of active and adequate bond coverage as well as liability insurance as part of the application process to obtain or renew an LAFD operational permit.	24	Policymakers	A
2.4 Direct LAFD to submit/upload all bond and insurance documents to the system maintained by the CAO's Risk Management Division.	24	Policymakers	A
2.5 Work with the CAO Risk Management Division and DCP/OZA to periodically review the status of all oil and gas well surety bonds and insurance policies on file with the City. For operators and/or sites lacking the required and valid surety bond, consult with the City Attorney to evaluate options for resolution.	24	Petroleum Administrator	B

2.6	Work with responsible City Departments to file claims on surety bonds or insurance policies when drilling site operators demonstrate a pattern of noncompliance with legal requirements and conditions of approval.	25	Petroleum Administrator	B
III.	**GENERATING CITY REVENUE FROM OIL AND GAS WELLS**			
3.1	Amend the LAMC to allow the City to recover costs associated with enhanced oversight activities including: (1) issuing licenses and permits; (2) performing investigations, inspections, and audits; and (3) administrative enforcement and adjudication of oil and gas wells.	31	Policymakers	A
3.2	Perform a cost-benefit analysis to explore the feasibility of reintroducing a barrel tax for voter approval. At minimum, the cost-benefit analysis should consider: (1) projected extraction volume based on historical records and likelihood of future drilling activity in the City; (2) cost of placing the measure on the ballot; (3) ongoing administrative costs associated with imposing and collecting the tax; and (4) the appropriate per-barrel tax rate.	31	Policymakers	B
3.3	Direct all Departments to verify any oil or gas exploration on or under the real property they control. Once an inventory has been developed, determine whether to renew or renegotiate any expired lease agreements	32	Policymakers	A
3.4	Formally transfer the responsibility for oversight of oil and gas extracted from City-owned properties to the Petroleum Administrator.	32	Policymakers	B
3.5	For future lease agreements, consider adding terms that would require payments into a restoration/abandonment fund, modeled after the Rancho Park lease.	32	Policymakers	B
3.6	Perform title research to identify subsurface parcels whose mineral rights are owned by the City. For those related to oil fields with extraction activity, determine whether the City received appropriate royalty payments. For	32	Petroleum Administrator	A

	well operators who did not pay the City royalties it was owed, consult with the City Attorney to explore legal options.			
3.7	Collaborate with LAFD and DOGGR to determine whether former lessees fulfilled their obligations to plug and abandon wells on City-owned property in accordance with State law, and restore the site to its natural condition.	32	Petroleum Administrator	A
3.8	For lessees who did not fulfill their obligations to plug and abandon wells in accordance with DOGGR requirements, consult with the City Attorney to explore legal options, and propose any remedial actions that should be taken by the City.	32	Petroleum Administrator	A
3.9	Develop and implement an improved reporting process to provide assurance of compliance with extraction agreements with well operators, including periodic reviews of royalty payments.	32	Petroleum Administrator	B
IV.	**INCREASING TRANSPARENCY AND INFORMATION SHARING**			
4.1	Collaborate with responsible City Departments to develop short- and medium-term plans to identify and compile relevant records that are currently located in the City Archives or maintained by City Departments.	36	Petroleum Administrator	A
4.2	Consult the City Attorney to establish formal information sharing agreements with external regulatory entities.	36	Petroleum Administrator	A
4.3	Collaborate with responsible City Departments to determine whether existing technology platforms can be used to develop a centralized database of oil and gas drilling sites and relevant information. If not, the Petroleum Administrator should identify reasonable, cost-effective alternatives.	36	Petroleum Administrator	A
4.4	Develop a public-facing website to increase transparency and facilitate public engagement on issues related to oil and gas drilling sites.	36	Petroleum Administrator	B
4.5	Consider revising the LAMC to require operators of drilling sites to notify the	36	Policymakers	B

	Petroleum Administrator of communications submitted to and received from external regulatory agencies. City officials should consult with the Petroleum Administrator to identify sources and types of information to be reported. At minimum, the notification requirement should include a timeframe within which the information must be provided.			
4.6	Consider revising the LAMC to require oil and gas operators to notify the Petroleum Administrator when complaints are received. At minimum, the notification requirement should include a timeframe within which complaints should be forwarded to the Petroleum Administrator.	36	Policymakers	B

***A –High Priority** - The recommendation pertains to a serious or materially significant audit finding or control weakness. Due to the seriousness or significance of the matter, immediate management attention and appropriate corrective action is warranted.*

***B –Medium Priority** - The recommendation pertains to a moderately significant or potentially serious audit finding or control weakness. Reasonably prompt corrective action should be taken by management to address the matter. Recommendation should be implemented no later than six months.*

***C –Lower Priority** - The recommendation pertains to an audit finding or control weakness of relatively minor significance or concern. The timing of any corrective action is left to management's discretion.*

***N/A** - Not Applicable*

2021-22 SESSION

SENATE
THIRD READING PACKET

WEDNESDAY, MAY 26, 2021

JONAS AUSTIN
Director

OFFICE OF SENATE FLOOR ANALYSES
651-1520

SENATE THIRD READING PACKET

Attached are analyses of bills on the Daily File for Wednesday, May 26, 2021.

Note	Measure	Author	Location
+	SB 2	Bradford	Senate Bills - Third Reading File
+	SB 4	Gonzalez	Senate Bills - Third Reading File
RA	SB 9	Atkins	Senate Bills - Third Reading File
	SB 10	Wiener	Senate Bills - Third Reading File
	SB 12	McGuire	Senate Bills - Third Reading File
+	SB 14	Portantino	Senate Bills - Third Reading File
+	SB 15	Portantino	Senate Bills - Third Reading File
+	SB 16	Skinner	Senate Bills - Third Reading File
+	SB 17	Pan	Senate Bills - Third Reading File
+	SB 18	Skinner	Senate Bills - Third Reading File
	SB 19	Glazer	Special Consent Calendar No.3
	SB 20	Dodd	Senate Bills - Third Reading File
+	SB 22	Glazer	Senate Bills - Third Reading File
	SB 23	Rubio	Special Consent Calendar No.3
+	SB 26	Skinner	Senate Bills - Third Reading File
+	SB 27	Skinner	Senate Bills - Third Reading File
+	SB 34	Umberg	Senate Bills - Third Reading File
	SB 37	Cortese	Special Consent Calendar No.3
+	SB 38	Wieckowski	Senate Bills - Third Reading File
	SB 39	Grove	Senate Bills - Third Reading File
+	SB 40	Hurtado	Senate Bills - Third Reading File
	SB 41	Umberg	Senate Bills - Third Reading File
RA	SB 42	Wieckowski	Special Consent Calendar No.3
	SB 44	Allen	Senate Bills - Third Reading File
	SB 45	Portantino	Senate Bills - Third Reading File
	SB 47	Limón	Senate Bills - Third Reading File
	SB 48	Limón	Senate Bills - Third Reading File
RA	SB 49	Umberg	Special Consent Calendar No.3
+	SB 50	Limón	Senate Bills - Third Reading File
+	SB 53	Leyva	Senate Bills - Third Reading File
+	SB 56	Durazo	Senate Bills - Third Reading File
+	SB 61	Hurtado	Senate Bills - Third Reading File
	SB 63	Stern	Senate Bills - Third Reading File
+	SB 64	Leyva	Senate Bills - Third Reading File
	SB 66	Allen	Special Consent Calendar No.3
+	SB 68	Becker	Senate Bills - Third Reading File
	SB 69	McGuire	Special Consent Calendar No.3
+	SB 70	Rubio	Senate Bills - Third Reading File
	SB 72	Rubio	Special Consent Calendar No.3
	SB 76	Nielsen	Special Consent Calendar No.3
	SB 80	McGuire	Special Consent Calendar No.3
RA	SB 81	Skinner	Senate Bills - Third Reading File
+	SB 83	Allen	Senate Bills - Third Reading File
	SB 97	Roth	Special Consent Calendar No.3
+	SB 98	McGuire	Senate Bills - Third Reading File
	SB 107	Wiener	Senate Bills - Third Reading File

+ ADDS
RA Revised Analysis
* Analysis pending

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THIRD READING

Bill No: SB 47
Author: Limón (D)
Amended: 3/15/21
Vote: 21

SENATE NATURAL RES. & WATER COMMITTEE: 6-2, 4/13/21
AYES: Laird, Allen, Eggman, Hertzberg, Limón, Stern
NOES: Jones, Grove
NO VOTE RECORDED: Hueso

SENATE APPROPRIATIONS COMMITTEE: 5-2, 5/20/21
AYES: Portantino, Bradford, Kamlager, Laird, Wieckowski
NOES: Bates, Jones

SUBJECT: Oil and gas: hazardous and idle-deserted wells and production facilities: expenditure limitations

SOURCE: Author

DIGEST: This bill increases the annual expenditure limit from the Oil, Gas and Geothermal Administration Fund, the principal source of funding for the Geologic Energy Management Division from a production fee assessed on oil and gas production in the state, for the plugging and abandonment of hazardous or idle-deserted wells to $10 million, and provides that any of those funds not used annually for that purpose be retained, as specified.

ANALYSIS:

Existing law:

1) Establishes the Geologic Energy Management Division (CalGEM) in the Department of Conservation. CalGEM regulates oil and gas production in the state, and CalGEM's leader is the State Oil and Gas Supervisor (supervisor).

2) Provides that the purposes of the state's oil and gas conservation laws include protecting public health and safety and environmental quality, including the reduction and mitigation of greenhouse gas emissions associated with the development of hydrocarbon and geothermal resources in a manner that meets the energy needs of the state.

   a) The supervisor shall coordinate with other state agencies and others to further the goals of the California Global Warming Solutions Act of 2006 and to help support the state's clean energy goals. (Public Resources Code (PRC) §3011)

3) Directs the supervisor to so supervise the drilling, operation, maintenance, and abandonment of wells and the operation, maintenance, and removal or abandonment of tanks and facilities attendant to oil and gas production, as specified, so as to prevent, as far as possible, damage to life, health, property, and natural resources, as provided. (PRC §3106)

4) Classifies oil and gas wells based upon their use.

   a) An idle well is a well that is not in use, and has not been in use for at least 24 consecutive months, as specified. (PRC §3008)

   b) An idle well that has no operator or other responsible party to pay for its costs becomes an "idle-deserted" or "orphan" well, which is then the responsibility of the state to plug and abandon. (PRC §3251, §3206.3)

   c) Long-term idle wells are those wells that have been idle for at least eight years. (PRC §3008)

5) Holds the current operator, or the previous operator, as provided, of an orphan well that produced oil, gas, or other hydrocarbons or was used for injection, responsible for the proper plugging and abandonment of the well or the decommissioning of idle-deserted production facilities. (PRC §3237)

6) Authorizes the supervisor to order the plugging and abandonment, or decommissioning of a hazardous or idle-deserted well or facility, as specified. (PRC §3251, §3255)

7) Requires an operator to either file with the supervisor certain annual idle well fees per well that increase the longer the well has been idle, or file an idle well management plan with the supervisor that eliminates between 4% - 6% of the long-term idle wells each year. Failure to pay idle well fees or file a plan is sufficient evidence for the well to be considered legally deserted.

8) Prohibits CalGEM from expending no more than $3 million in any one fiscal year from FY 2018 - 2019 to FY 2021-2022, inclusive, for plugging and abandoning and decommissioning hazardous and idle-deserted wells, and hazardous or deserted facilities from the Oil, Gas and Geothermal Administration Fund (OGGAF).

   a) OGGAF is funded by fees paid by oil and gas well operators based upon the amount of oil and/or natural gas they produce annually, and is the principal source of funding for CalGEM.

   b) As of FY 2022-2023, the $3 million is reduced to $1 million. (PRC §3258).

9) Establishes the Oil and Gas Environmental Remediation (OGER) Account in the OGGAF to be administered and managed by CalGEM, and requires that the moneys in the OGER Account be used, upon appropriation by the Legislature, to plug and abandon oil and gas wells, decommission attendant facilities, or otherwise remediate sites that the supervisor determines could pose a danger to life, health, water quality, wildlife, or natural resources if there is no operator determined by the supervisor to be responsible for the remediation or who is able to respond. (PRC §§3260 *et seq*.)

This bill increases the annual expenditure limit from OGGAF for the plugging and abandonment of hazardous or idle-deserted wells to $10 million, and provides that any of those funds not used annually for that purpose be retained, as specified. In particular, this bill:

1) Increases the amount that CalGEM can spend to plug and abandon hazardous or idle-deserted wells and decommission hazardous or deserted facilities from OGGAF to $10 million annually starting with FY 2022-2023.

2) Provides, also commencing with FY 2022 – 2023, that in any fiscal year that CalGEM expends less than the $10 million to plug and abandon hazardous or idle-deserted wells and decommission hazardous or deserted facilities, the State Controller shall transfer from OGGAF to the OGER Account an amount equal to the difference of $10 million and what was spent for that fiscal year unless the OGER Account balance exceeds $100 million.

Background

According to data obtained from CalGEM's website, there are approximately 125,000 active and idle oil and gas wells in the state (2021 data) and related production facilities located in over 180 oil and gas fields. Of these wells, about 78,000 are active, and 47,500 are idle. Curiously, CalGEM has recently reclassified numerous legacy wells previously identified as "buried" to "idle" without making much use of the (relatively new) "unknown" category.

Active wells are those currently in use that either produce or inject fluids related to hydrocarbon production. Wells are often expensive to drill and to seal ("plug and abandon"). Therefore, operators may prefer to keep wells idle – sometimes for extended periods of time. Idle wells are more likely to become orphan wells. Orphan wells are deserted wells that the state has to address because no responsible operator has been found to do so. Orphan wells are likely to not be maintained consistently, and emissions from wells that fail or are failing may be hazardous to the surrounding environment, and public health and safety.

CalGEM has multiple methods – once a well and/or related production facility has been identified as orphan, deserted and/or hazardous – to fund plugging and abandonment and/or decommissioning. These include any existing and available indemnity bond or other financial surety provided by an operator covering that well or facility, seeking funds from a previous operator, as applicable, and using certain moneys available from three separate accounts – OGGAF, certain idle well fees deposited in the Hazardous and Idle-Deserted Well Abatement Fund (HIDWAF), and from the OGER account.

In addition, in the May revise, the Newsom Administration proposed spending $200 million from the General Fund to plug and abandon orphan wells as part of its Climate Resilience Budget Change Proposal. This proposal is pending before the Legislature. Spending General Fund monies on the plugging and abandonment of onshore wells appears to be a considerable change from established practice.

At CalGEM's request, the California Council on Science and Technology (CCST) investigated the status of the state's oil and gas wells in order to estimate the potential cost to the state should these wells become orphaned. The CCST report was released in January 2020. The CCST report suggested that there were about 5,540 wells that were either likely to be orphaned or at high risk of becoming orphaned soon. The potential liability to the state was estimated to be roughly $500 million net for these two categories alone, and could be much higher if additional wells became orphaned.

In March 2021, CalGEM released the second annual idle well report for the 2019 calendar year. The number of long-term idle wells remained relatively stable from 2018 to 2019 (17,576 to 17,560) as existing idle wells aged into long-term idle status and 543 long-term idle wells were either returned to operation or plugged and abandoned. The total number of idle wells increased to 37,095 from 29,292, although CalGEM states that part of that increase may be from the transition to a new database that may have delayed production reporting by some operators. During 2019 it appears that CalGEM identified 25 wells as orphan. CalGEM further identified 3,265 wells as potentially deserted due to failure to pay idle well fees by over 940 operators. CalGEM paid about $7.2 million on 14 contracts for the plugging and abandonment of 54 wells in FY 2017 – 2019.

As of June 30, 2020, the HIDWAF account had a balance of over $13 million. The Department of Finance subsequently made a temporary loan of $10 million from that account to the General Fund as steps were taken to address the pandemic.

Comments

The backlog of potentially deserted wells. Recent reforms at CalGEM have resulted in operators plugging and abandoning more wells and long-term idle wells. The reforms have also helped to identify what appear to be a few thousand potentially deserted wells that appear to have persisted from 2018 through 2019. An order-of-magnitude calculation (3,000 wells x the average Inland District 2019 well abandonment cost of about $87,000) suggests that the potential liability to address these wells could be easily over $100 million if all eventually become orphan. CalGEM's projections of plugging and abandoning up to 100 orphan wells annually with $3 million from OGGAF may well be optimistic unless all the orphan wells are shallow and are easy to plug and abandon. An increase in the annual amount available from OGGAF to fund plugging and abandonment of orphan wells and decommissioning attendant facilities would help to ensure that the state's taxpayers would not have to pay instead, depending upon the outcome of the May revise proposal to use General Fund monies for onshore wells. In addition, rolling over unspent funds to the OGER Account could help ensure that moneys are available in the event of very expensive plugging and abandonment operations – two recent wells in Los Angeles cost $1 million each.

The persistence of the backlog. In the 2019 idle well report, CalGEM reported the wells from 10 operators became orphan. While the time and effort for CalGEM to determine if there is a solvent operator or previous operator for a well or wells will vary, it seems reasonable to project that it will take an extended period of time for CalGEM to work through the 900+ operators that recent reform efforts have suggested may be defunct. The failure of a contract issued by CalGEM recently to plug and abandon orphan wells helps to explain why CalGEM spent somewhat less than authorized to plug and abandon wells from OGGAF a few years ago. The time required to determine whether a well is orphan suggests that this step is the limiting factor in how much plugging and abandonment the state can perform. The ability of CalGEM – even when using contractors to perform title searches or to track down corporate ownership – to declare a well orphan in a consistent and defensible way is unclear.

FISCAL EFFECT: Appropriation: No Fiscal Com.: Yes Local: No

According to the Senate Appropriations Committee:

- Ongoing costs of $9 million annually (OGGAF) due to increasing the annual spending authority for the CalGEM to plug deserted wells.

- CalGEM estimates costs of $1,062,000 in the first year and $989,000 ongoing (OGGAF) for six positions and limited-term contract authority to administer and oversee the increased spending on plugging and abandonment of hazardous or idle-deserted wells.

- OGGAF is funded by fees on oil and natural gas produced in California. Any state costs supported by OGGAF are recovered from operators of oil and gas wells.

SUPPORT: (Verified 5/21/21)

1000 Grandmothers for Future Generations
350 Bay Area Action
350 Conejo/San Fernando Valley
350 Humboldt
350 South Bay Los Angeles
350 Ventura County Climate Hub
Alliance of Nurses for Healthy Environments
Audubon California
California Coastal Protection Network
California Interfaith Power & Light
California League of Conservation Voters
Center for Biological Diversity
Citizens' Climate Lobby – Ventura Chapter
Clean Water Action
Climate 911
Climate First: Replacing Oil & Gas
Climate Health Now
Conejo Climate Coalition
County of Los Angeles
County of Ventura
Earthjustice

Environmental Defense Center
Environmental Working Group
Families Advocating for Chemical & Toxins Safety
Food & Water Watch
Greenpeace USA
Indivisible California Green Team
Indivisible Together We Will Los Gatos
Indivisible Ventura
Interfaith Climate Action Network of Contra Costa County
Long Beach Alliance for Clean Energy
Los Padres Forestwatch
Mi Familia Vota
Natural Resources Defense Council
Normal Heights Indivisible
Rodeo Citizens Association
Rooted in Resistance (Indivisible)
San Francisco Bay Physicians for Social Responsibility
Santa Barbara County Action Network
Santa Barbara Standing Rock Coalition
Sierra Club California
SoCal 350 Climate Action
Sunflower Alliance
Surfrider Foundation
Take Back Our Planet

OPPOSITION: (Verified 5/21/21)

California Independent Petroleum Association
California State Pipe Trades Council
International Association of Sheet Metal, Air, Rail and Transportation Workers, Sheet Metal Workers' Local Union No. 104
State Building and Construction Trades Council of California
Western States Petroleum Association

ARGUMENTS IN SUPPORT: According to the author, "[w]ithout a responsible operator, taxpayers will be the funding source of last resort for environmental remediation. The 2018 California Council on Science and Technology Report estimated California might already have 5,540 wells without a viable operator, resulting in taxpayer costs ranging from $500 million to billions of dollars. These wells are hazardous both to surrounding communities and the environment.

"SB 47 will increase CalGEM's annual spending authority to plug deserted wells from $3 million to $10 million and save any unspent funds until the account reaches $100 million.

"SB 47 is a significant step to ensure that the oil and gas industry pays from the remediation of hazards that the industry has historically left behind and those the State and taxpayers continue to inherit."

ARGUMENTS IN OPPOSITION: The California Independent Petroleum Association (CIPA) writing in opposition notes that the state has HIDWAF, the existing annual expenditure authority from OGGAF and recent changes in law have provided for additional bonding authority to CalGEM to help fund orphan well and facilities. CIPA objects to the "raid" of HIDWAF funds by the Department of Finance as these are funds used to pay for addressing orphan wells, and states that "California's taxpayers have not been on the hook for the remediation of a single onshore orphaned oil well."

CIPA continues by stating that its members "believe that the current body of law surrounding remediating orphaned wells is working well and does not need to be modified. Instead, the state needs to fully reimburse the HIDWAF and allow CalGEM to do its job of remediating orphaned wells using the money oil producers have paid towards this important effort."

The Western States Petroleum Association (WSPA) also objects to the HIDWAF loan, notes that CalGEM has expended fewer funds recently to address orphan wells than it could have, and proposes several amendments that, among other things, reduce the $10 million and $100 million statutory caps proposed in this bill.

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5/22/21 9:52:36

****** END ******

Summary for Policymakers

SPM

Summary for Policymakers

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SPM

Introduction

This Summary for Policymakers (SPM) presents key findings of the Working Group I (WGI) contribution to the Intergovernmental Panel on Climate Change (IPCC) Sixth Assessment Report (AR6)[1] on the physical science basis of climate change. The report builds upon the 2013 Working Group I contribution to the IPCC's Fifth Assessment Report (AR5) and the 2018–2019 IPCC Special Reports[2] of the AR6 cycle and incorporates subsequent new evidence from climate science.[3]

This SPM provides a high-level summary of the understanding of the current state of the climate, including how it is changing and the role of human influence, the state of knowledge about possible climate futures, climate information relevant to regions and sectors, and limiting human-induced climate change.

Based on scientific understanding, key findings can be formulated as statements of fact or associated with an assessed level of confidence indicated using the IPCC calibrated language.[4]

The scientific basis for each key finding is found in chapter sections of the main Report and in the integrated synthesis presented in the Technical Summary (hereafter TS), and is indicated in curly brackets. The AR6 WGI Interactive Atlas facilitates exploration of these key synthesis findings, and supporting climate change information, across the WGI reference regions.[5]

A. The Current State of the Climate

Since AR5, improvements in observationally based estimates and information from paleoclimate archives provide a comprehensive view of each component of the climate system and its changes to date. New climate model simulations, new analyses, and methods combining multiple lines of evidence lead to improved understanding of human influence on a wider range of climate variables, including weather and climate extremes. The time periods considered throughout this section depend upon the availability of observational products, paleoclimate archives and peer-reviewed studies.

A.1 It is unequivocal that human influence has warmed the atmosphere, ocean and land. Widespread and rapid changes in the atmosphere, ocean, cryosphere and biosphere have occurred.
{2.2, 2.3, Cross-Chapter Box 2.3, 3.3, 3.4, 3.5, 3.6, 3.8, 5.2, 5.3, 6.4, 7.3, 8.3, 9.2, 9.3, 9.5, 9.6, Cross-Chapter Box 9.1} (Figure SPM.1, Figure SPM.2)

A.1.1 Observed increases in well-mixed greenhouse gas (GHG) concentrations since around 1750 are unequivocally caused by human activities. Since 2011 (measurements reported in AR5), concentrations have continued to increase in the atmosphere, reaching annual averages of 410 parts per million (ppm) for carbon dioxide (CO_2), 1866 parts per billion (ppb) for methane (CH_4), and 332 ppb for nitrous oxide (N_2O) in 2019.[6] Land and ocean have taken up a near-constant proportion (globally about 56% per year) of CO_2 emissions from human activities over the past six decades, with regional differences (*high confidence*).[7]
{2.2, 5.2, 7.3, TS.2.2, Box TS.5}

1 Decision IPCC/XLVI-2.

2 The three Special Reports are: Global Warming of 1.5°C: An IPCC Special Report on the impacts of global warming of 1.5°C above pre-industrial levels and related global greenhouse gas emission pathways, in the context of strengthening the global response to the threat of climate change, sustainable development, and efforts to eradicate poverty (SR1.5); Climate Change and Land: An IPCC Special Report on climate change, desertification, land degradation, sustainable land management, food security, and greenhouse gas fluxes in terrestrial ecosystems (SRCCL); IPCC Special Report on the Ocean and Cryosphere in a Changing Climate (SROCC).

3 The assessment covers scientific literature accepted for publication by 31 January 2021.

4 Each finding is grounded in an evaluation of underlying evidence and agreement. A level of confidence is expressed using five qualifiers: very low, low, medium, high and very high, and typeset in italics, for example, *medium confidence*. The following terms have been used to indicate the assessed likelihood of an outcome or result: virtually certain 99–100% probability; very likely 90–100%; likely 66–100%; about as likely as not 33–66%; unlikely 0–33%; very unlikely 0–10%; and exceptionally unlikely 0–1%. Additional terms (extremely likely 95–100%; more likely than not >50–100%; and extremely unlikely 0–5%) are also used when appropriate. Assessed likelihood is typeset in italics, for example, *very likely*. This is consistent with AR5. In this Report, unless stated otherwise, square brackets [x to y] are used to provide the assessed *very likely* range, or 90% interval.

5 The Interactive Atlas is available at https://interactive-atlas.ipcc.ch

6 Other GHG concentrations in 2019 were: perfluorocarbons (PFCs) – 109 parts per trillion (ppt) CF_4 equivalent; sulphur hexafluoride (SF_6) – 10 ppt; nitrogen trifluoride (NF_3) – 2 ppt; hydrofluorocarbons (HFCs) – 237 ppt HFC-134a equivalent; other Montreal Protocol gases (mainly chlorofluorocarbons (CFCs) and hydrochlorofluorocarbons (HCFCs)) – 1032 ppt CFC-12 equivalent). Increases from 2011 are 19 ppm for CO_2, 63 ppb for CH_4 and 8 ppb for N_2O.

7 Land and ocean are not substantial sinks for other GHGs.

A.1.2 Each of the last four decades has been successively warmer than any decade that preceded it since 1850. Global surface temperature[8] in the first two decades of the 21st century (2001–2020) was 0.99 [0.84 to 1.10] °C higher than 1850–1900.[9] Global surface temperature was 1.09 [0.95 to 1.20] °C higher in 2011–2020 than 1850–1900, with larger increases over land (1.59 [1.34 to 1.83] °C) than over the ocean (0.88 [0.68 to 1.01] °C). The estimated increase in global surface temperature since AR5 is principally due to further warming since 2003–2012 (+0.19 [0.16 to 0.22] °C). Additionally, methodological advances and new datasets contributed approximately 0.1°C to the updated estimate of warming in AR6.[10]
{2.3, Cross-Chapter Box 2.3} (Figure SPM.1)

A.1.3 The *likely* range of total human-caused global surface temperature increase from 1850–1900 to 2010–2019[11] is 0.8°C to 1.3°C, with a best estimate of 1.07°C. It is *likely* that well-mixed GHGs contributed a warming of 1.0°C to 2.0°C, other human drivers (principally aerosols) contributed a cooling of 0.0°C to 0.8°C, natural drivers changed global surface temperature by –0.1°C to +0.1°C, and internal variability changed it by –0.2°C to +0.2°C. It is *very likely* that well-mixed GHGs were the main driver[12] of tropospheric warming since 1979 and *extremely likely* that human-caused stratospheric ozone depletion was the main driver of cooling of the lower stratosphere between 1979 and the mid-1990s.
{3.3, 6.4, 7.3, TS.2.3, Cross-Section Box TS.1} (Figure SPM.2)

A.1.4 Globally averaged precipitation over land has *likely* increased since 1950, with a faster rate of increase since the 1980s (*medium confidence*). It is *likely* that human influence contributed to the pattern of observed precipitation changes since the mid-20th century and *extremely likely* that human influence contributed to the pattern of observed changes in near-surface ocean salinity. Mid-latitude storm tracks have *likely* shifted poleward in both hemispheres since the 1980s, with marked seasonality in trends (*medium confidence*). For the Southern Hemisphere, human influence *very likely* contributed to the poleward shift of the closely related extratropical jet in austral summer.
{2.3, 3.3, 8.3, 9.2, TS.2.3, TS.2.4, Box TS.6}

A.1.5 Human influence is *very likely* the main driver of the global retreat of glaciers since the 1990s and the decrease in Arctic sea ice area between 1979–1988 and 2010–2019 (decreases of about 40% in September and about 10% in March). There has been no significant trend in Antarctic sea ice area from 1979 to 2020 due to regionally opposing trends and large internal variability. Human influence *very likely* contributed to the decrease in Northern Hemisphere spring snow cover since 1950. It is *very likely* that human influence has contributed to the observed surface melting of the Greenland Ice Sheet over the past two decades, but there is only *limited evidence*, with *medium agreement*, of human influence on the Antarctic Ice Sheet mass loss.
{2.3, 3.4, 8.3, 9.3, 9.5, TS.2.5}

A.1.6 It is *virtually certain* that the global upper ocean (0–700 m) has warmed since the 1970s and *extremely likely* that human influence is the main driver. It is *virtually certain* that human-caused CO_2 emissions are the main driver of current global acidification of the surface open ocean. There is *high confidence* that oxygen levels have dropped in many upper ocean regions since the mid-20th century and *medium confidence* that human influence contributed to this drop.
{2.3, 3.5, 3.6, 5.3, 9.2, TS.2.4}

A.1.7 Global mean sea level increased by 0.20 [0.15 to 0.25] m between 1901 and 2018. The average rate of sea level rise was 1.3 [0.6 to 2.1] mm yr^{-1} between 1901 and 1971, increasing to 1.9 [0.8 to 2.9] mm yr^{-1} between 1971 and 2006, and further increasing to 3.7 [3.2 to 4.2] mm yr^{-1} between 2006 and 2018 (*high confidence*). Human influence was *very likely* the main driver of these increases since at least 1971.
{2.3, 3.5, 9.6, Cross-Chapter Box 9.1, Box TS.4}

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8 The term 'global surface temperature' is used in reference to both global mean surface temperature and global surface air temperature throughout this SPM. Changes in these quantities are assessed with *high confidence* to differ by at most 10% from one another, but conflicting lines of evidence lead to *low confidence* in the sign (direction) of any difference in long-term trend. {Cross-Section Box TS.1}

9 The period 1850–1900 represents the earliest period of sufficiently globally complete observations to estimate global surface temperature and, consistent with AR5 and SR1.5, is used as an approximation for pre-industrial conditions.

10 Since AR5, methodological advances and new datasets have provided a more complete spatial representation of changes in surface temperature, including in the Arctic. These and other improvements have also increased the estimate of global surface temperature change by approximately 0.1°C, but this increase does not represent additional physical warming since AR5.

11 The period distinction with A.1.2 arises because the attribution studies consider this slightly earlier period. The observed warming to 2010–2019 is 1.06 [0.88 to 1.21] °C.

12 Throughout this SPM, 'main driver' means responsible for more than 50% of the change.

A.1.8 Changes in the land biosphere since 1970 are consistent with global warming: climate zones have shifted poleward in both hemispheres, and the growing season has on average lengthened by up to two days per decade since the 1950s in the Northern Hemisphere extratropics (*high confidence*).
{2.3, TS.2.6}

Human influence has warmed the climate at a rate that is unprecedented in at least the last 2000 years

Changes in global surface temperature relative to 1850–1900

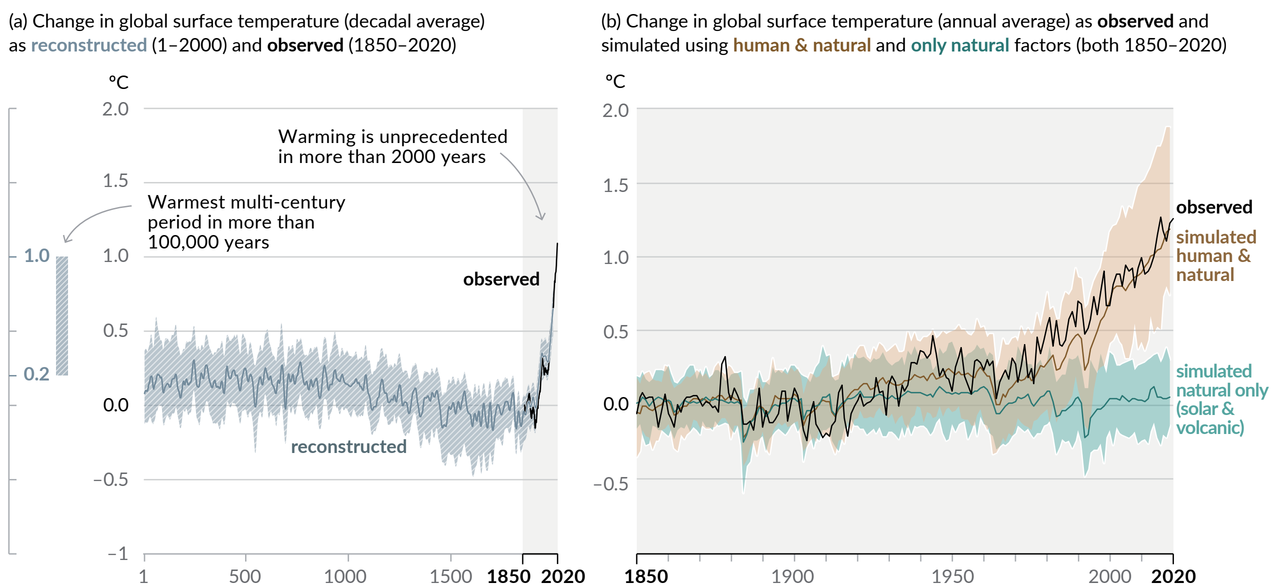

Figure SPM.1 | History of global temperature change and causes of recent warming

Panel (a) Changes in global surface temperature reconstructed from paleoclimate archives (solid grey line, years 1–2000) **and from direct observations** (solid black line, 1850–2020), both relative to 1850–1900 and decadally averaged. The vertical bar on the left shows the estimated temperature (*very likely* range) during the warmest multi-century period in at least the last 100,000 years, which occurred around 6500 years ago during the current interglacial period (Holocene). The Last Interglacial, around 125,000 years ago, is the next most recent candidate for a period of higher temperature. These past warm periods were caused by slow (multi-millennial) orbital variations. The grey shading with white diagonal lines shows the *very likely* ranges for the temperature reconstructions.

Panel (b) Changes in global surface temperature over the past 170 years (black line) relative to 1850–1900 and annually averaged, compared to Coupled Model Intercomparison Project Phase 6 (CMIP6) climate model simulations (see Box SPM.1) of the temperature response to both human and natural drivers (brown) and to only natural drivers (solar and volcanic activity, green). Solid coloured lines show the multi-model average, and coloured shades show the *very likely* range of simulations. (See Figure SPM.2 for the assessed contributions to warming).

{2.3.1; Cross-Chapter Box 2.3; 3.3; TS.2.2; Cross-Section Box TS.1, Figure 1a}

Observed warming is driven by emissions from human activities, with greenhouse gas warming partly masked by aerosol cooling

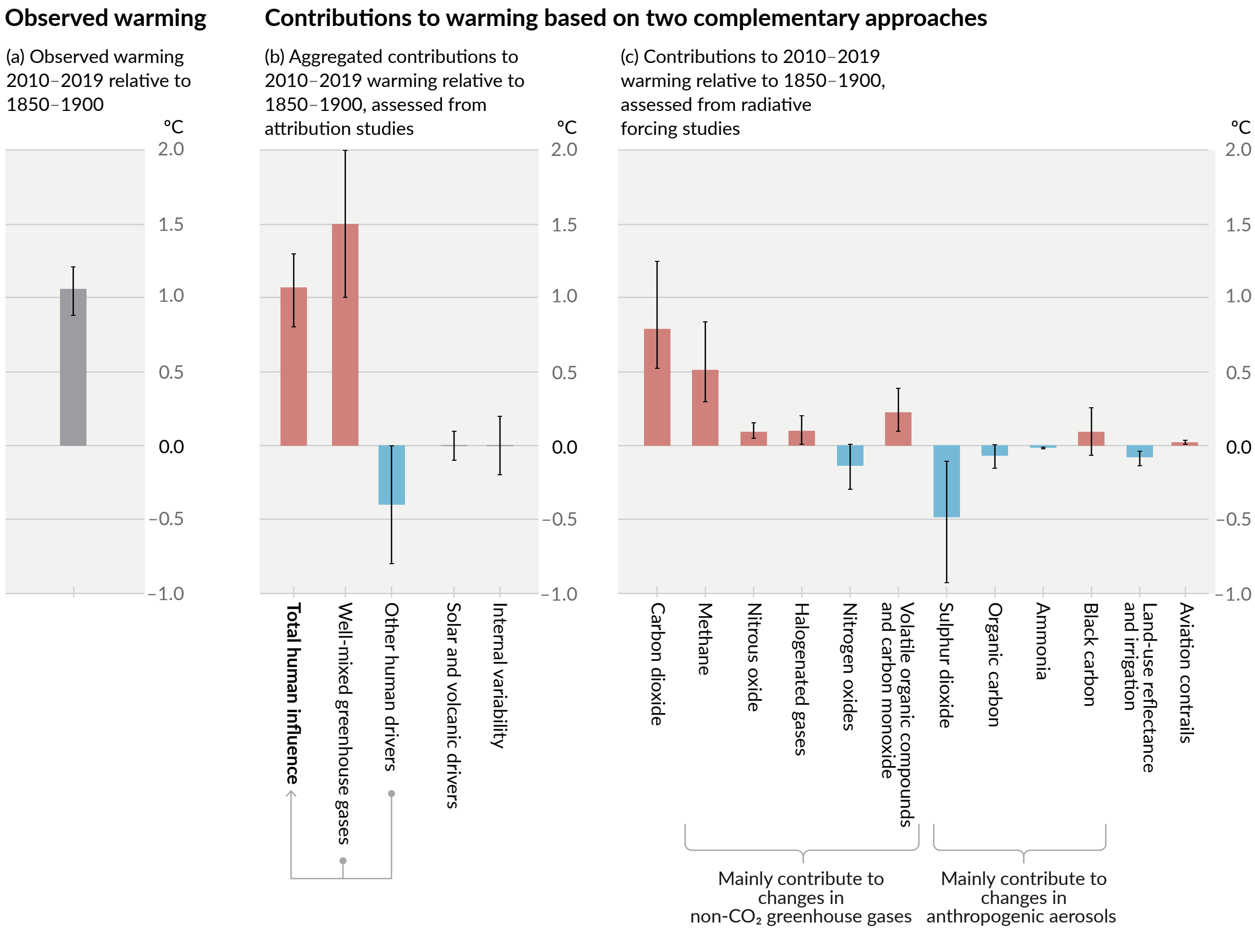

Figure SPM.2 | Assessed contributions to observed warming in 2010–2019 relative to 1850–1900

Panel (a) Observed global warming (increase in global surface temperature). Whiskers show the *very likely* range.

Panel (b) Evidence from attribution studies, which synthesize information from climate models and observations. The panel shows temperature change attributed to: total human influence; changes in well-mixed greenhouse gas concentrations; other human drivers due to aerosols, ozone and land-use change (land-use reflectance); solar and volcanic drivers; and internal climate variability. Whiskers show *likely* ranges.

Panel (c) Evidence from the assessment of radiative forcing and climate sensitivity. The panel shows temperature changes from individual components of human influence: emissions of greenhouse gases, aerosols and their precursors; land-use changes (land-use reflectance and irrigation); and aviation contrails. Whiskers show *very likely* ranges. Estimates account for both direct emissions into the atmosphere and their effect, if any, on other climate drivers. For aerosols, both direct effects (through radiation) and indirect effects (through interactions with clouds) are considered.

{Cross-Chapter Box 2.3, 3.3.1, 6.4.2, 7.3}

A.2 The scale of recent changes across the climate system as a whole – and the present state of many aspects of the climate system – are unprecedented over many centuries to many thousands of years. {2.2, 2.3, Cross-Chapter Box 2.1, 5.1} (Figure SPM.1)

A.2.1 In 2019, atmospheric CO_2 concentrations were higher than at any time in at least 2 million years (*high confidence*), and concentrations of CH_4 and N_2O were higher than at any time in at least 800,000 years (*very high confidence*). Since 1750, increases in CO_2 (47%) and CH_4 (156%) concentrations far exceed – and increases in N_2O (23%) are similar to – the natural multi-millennial changes between glacial and interglacial periods over at least the past 800,000 years (*very high confidence*).
{2.2, 5.1, TS.2.2}

A.2.2 Global surface temperature has increased faster since 1970 than in any other 50-year period over at least the last 2000 years (*high confidence*). Temperatures during the most recent decade (2011–2020) exceed those of the most recent multi-century warm period, around 6500 years ago[13] [0.2°C to 1°C relative to 1850–1900] (*medium confidence*). Prior to that, the next most recent warm period was about 125,000 years ago, when the multi-century temperature [0.5°C to 1.5°C relative to 1850–1900] overlaps the observations of the most recent decade (*medium confidence*).
{2.3, Cross-Chapter Box 2.1, Cross-Section Box TS.1} (Figure SPM.1)

A.2.3 In 2011–2020, annual average Arctic sea ice area reached its lowest level since at least 1850 (*high confidence*). Late summer Arctic sea ice area was smaller than at any time in at least the past 1000 years (*medium confidence*). The global nature of glacier retreat since the 1950s, with almost all of the world's glaciers retreating synchronously, is unprecedented in at least the last 2000 years (*medium confidence*).
{2.3, TS.2.5}

A.2.4 Global mean sea level has risen faster since 1900 than over any preceding century in at least the last 3000 years (*high confidence*). The global ocean has warmed faster over the past century than since the end of the last deglacial transition (around 11,000 years ago) (*medium confidence*). A long-term increase in surface open ocean pH occurred over the past 50 million years (*high confidence*). However, surface open ocean pH as low as recent decades is unusual in the last 2 million years (*medium confidence*).
{2.3, TS.2.4, Box TS.4}

A.3 Human-induced climate change is already affecting many weather and climate extremes in every region across the globe. Evidence of observed changes in extremes such as heatwaves, heavy precipitation, droughts, and tropical cyclones, and, in particular, their attribution to human influence, has strengthened since AR5. {2.3, 3.3, 8.2, 8.3, 8.4, 8.5, 8.6, Box 8.1, Box 8.2, Box 9.2, 10.6, 11.2, 11.3, 11.4, 11.6, 11.7, 11.8, 11.9, 12.3} (Figure SPM.3)

A.3.1 It is *virtually certain* that hot extremes (including heatwaves) have become more frequent and more intense across most land regions since the 1950s, while cold extremes (including cold waves) have become less frequent and less severe, with *high confidence* that human-induced climate change is the main driver[14] of these changes. Some recent hot extremes observed over the past decade would have been *extremely unlikely* to occur without human influence on the climate system. Marine heatwaves have approximately doubled in frequency since the 1980s (*high confidence*), and human influence has *very likely* contributed to most of them since at least 2006.
{Box 9.2, 11.2, 11.3, 11.9, TS.2.4, TS.2.6, Box TS.10} (Figure SPM.3)

A.3.2 The frequency and intensity of heavy precipitation events have increased since the 1950s over most land area for which observational data are sufficient for trend analysis (*high confidence*), and human-induced climate change is *likely* the main driver. Human-induced climate change has contributed to increases in agricultural and ecological droughts[15] in some regions due to increased land evapotranspiration[16] (*medium confidence*).
{8.2, 8.3, 11.4, 11.6, 11.9, TS.2.6, Box TS.10} (Figure SPM.3)

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13 As stated in section B.1, even under the very low emissions scenario SSP1-1.9, temperatures are assessed to remain elevated above those of the most recent decade until at least 2100 and therefore warmer than the century-scale period 6500 years ago.

14 As indicated in footnote 12, throughout this SPM, 'main driver' means responsible for more than 50% of the change.

15 Agricultural and ecological drought (depending on the affected biome): a period with abnormal soil moisture deficit, which results from combined shortage of precipitation and excess evapotranspiration, and during the growing season impinges on crop production or ecosystem function in general (see Annex VII: Glossary). Observed changes in meteorological droughts (precipitation deficits) and hydrological droughts (streamflow deficits) are distinct from those in agricultural and ecological droughts and are addressed in the underlying AR6 material (Chapter 11).

16 The combined processes through which water is transferred to the atmosphere from open water and ice surfaces, bare soils and vegetation that make up the Earth's surface (Glossary).

A.3.3 Decreases in global land monsoon precipitation[17] from the 1950s to the 1980s are partly attributed to human-caused Northern Hemisphere aerosol emissions, but increases since then have resulted from rising GHG concentrations and decadal to multi-decadal internal variability (*medium confidence*). Over South Asia, East Asia and West Africa, increases in monsoon precipitation due to warming from GHG emissions were counteracted by decreases in monsoon precipitation due to cooling from human-caused aerosol emissions over the 20th century (*high confidence*). Increases in West African monsoon precipitation since the 1980s are partly due to the growing influence of GHGs and reductions in the cooling effect of human-caused aerosol emissions over Europe and North America (*medium confidence*).
{2.3, 3.3, 8.2, 8.3, 8.4, 8.5, 8.6, Box 8.1, Box 8.2, 10.6, Box TS.13}

A.3.4 It is *likely* that the global proportion of major (Category 3–5) tropical cyclone occurrence has increased over the last four decades, and it is *very likely* that the latitude where tropical cyclones in the western North Pacific reach their peak intensity has shifted northward; these changes cannot be explained by internal variability alone (*medium confidence*). There is *low confidence* in long-term (multi-decadal to centennial) trends in the frequency of all-category tropical cyclones. Event attribution studies and physical understanding indicate that human-induced climate change increases heavy precipitation associated with tropical cyclones (*high confidence*), but data limitations inhibit clear detection of past trends on the global scale.
{8.2, 11.7, Box TS.10}

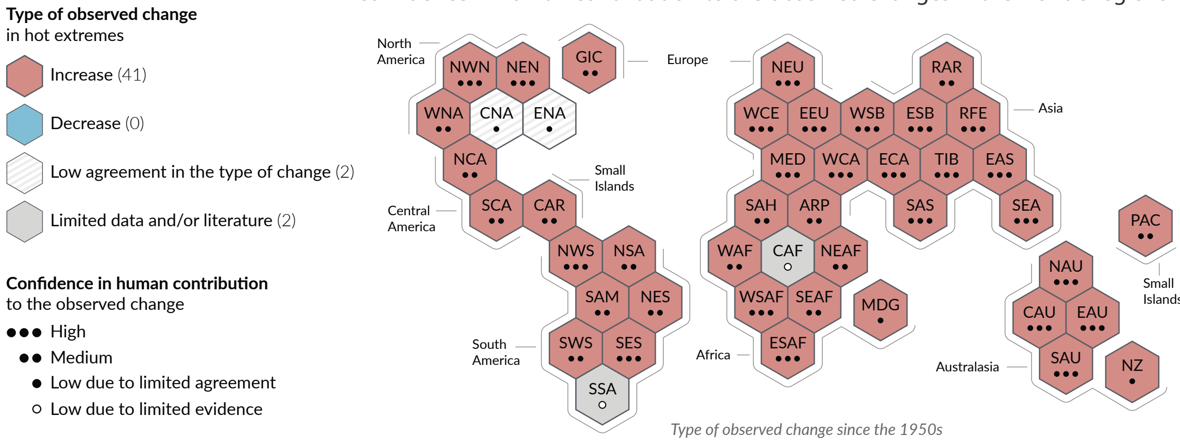
A.3.5 Human influence has *likely* increased the chance of compound extreme events[18] since the 1950s. This includes increases in the frequency of concurrent heatwaves and droughts on the global scale (*high confidence*), fire weather in some regions of all inhabited continents (*medium confidence*), and compound flooding in some locations (*medium confidence*).
{11.6, 11.7, 11.8, 12.3, 12.4, TS.2.6, Table TS.5, Box TS.10}

17 The global monsoon is defined as the area in which the annual range (local summer minus local winter) of precipitation is greater than 2.5 mm day^{-1} (Glossary). Global land monsoon precipitation refers to the mean precipitation over land areas within the global monsoon.

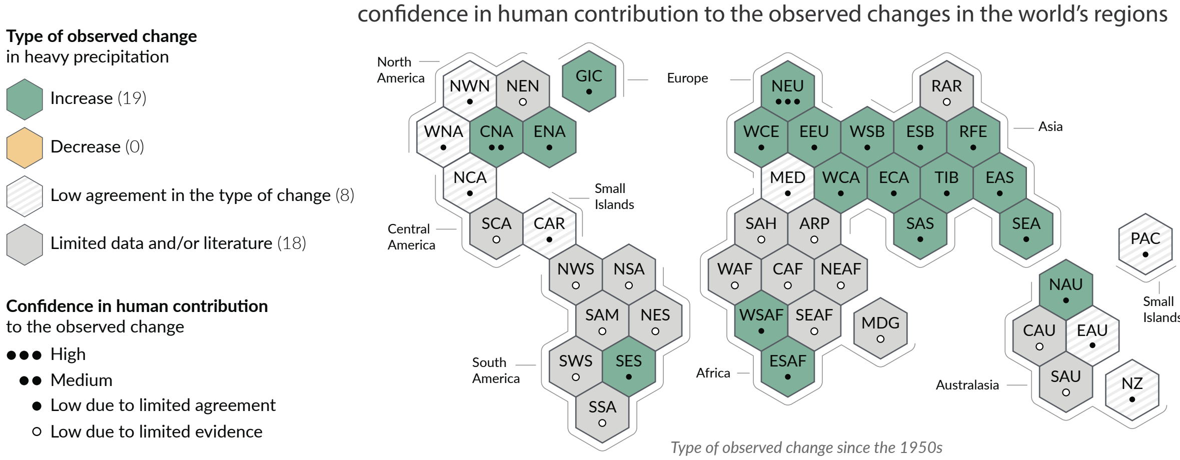
18 Compound extreme events are the combination of multiple drivers and/or hazards that contribute to societal or environmental risk (Glossary). Examples are concurrent heatwaves and droughts, compound flooding (e.g., a storm surge in combination with extreme rainfall and/or river flow), compound fire weather conditions (i.e., a combination of hot, dry and windy conditions), or concurrent extremes at different locations.

Climate change is already affecting every inhabited region across the globe, with human influence contributing to many observed changes in weather and climate extremes

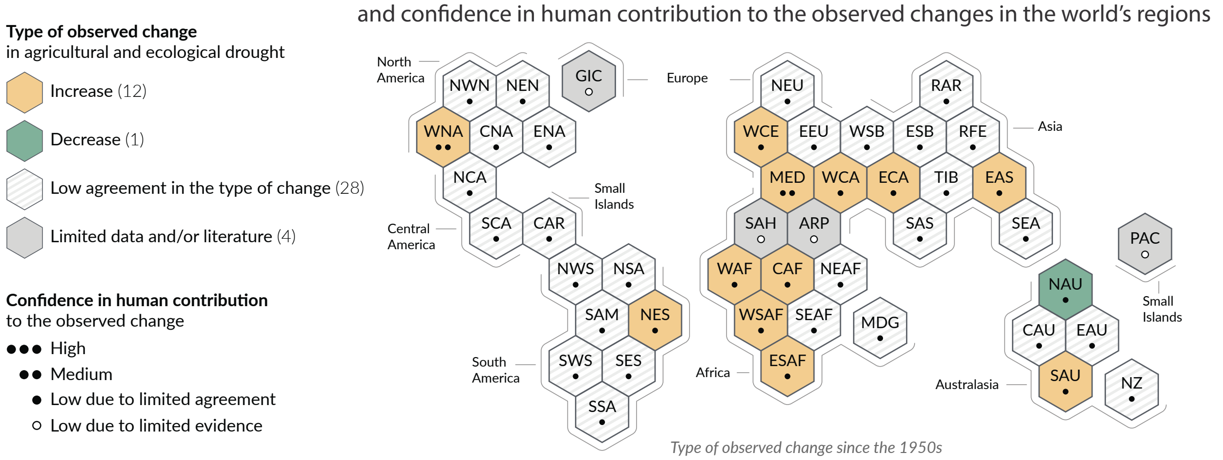
(a) Synthesis of assessment of observed change in **hot extremes** and confidence in human contribution to the observed changes in the world's regions



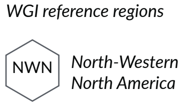
(b) Synthesis of assessment of observed change in **heavy precipitation** and confidence in human contribution to the observed changes in the world's regions



(c) Synthesis of assessment of observed change in **agricultural and ecological drought** and confidence in human contribution to the observed changes in the world's regions



Each hexagon corresponds to one of the IPCC AR6 WGI reference regions



IPCC AR6 WGI reference regions: **North America: NWN** *(North-Western North America,* **NEN** *(North-Eastern North America),* **WNA** *(Western North America),* **CNA** *(Central North America),* **ENA** *(Eastern North America),* **Central America: NCA** *(Northern Central America),* **SCA** *(Southern Central America),* **CAR** *(Caribbean),* **South America: NWS** *(North-Western South America),* **NSA** *(Northern South America),* **NES** *(North-Eastern South America),* **SAM** *(South American Monsoon),* **SWS** *(South-Western South America),* **SES** *(South-Eastern South America),* **SSA** *(Southern South America),* **Europe: GIC** *(Greenland/Iceland),* **NEU** *(Northern Europe),* **WCE** *(Western and Central Europe),* **EEU** *(Eastern Europe),* **MED** *(Mediterranean),* **Africa: MED** *(Mediterranean),* **SAH** *(Sahara),* **WAF** *(Western Africa),* **CAF** *(Central Africa),* **NEAF** *(North Eastern Africa),* **SEAF** *(South Eastern Africa),* **WSAF** *(West Southern Africa),* **ESAF** *(East Southern Africa),* **MDG** *(Madagascar),* **Asia: RAR** *(Russian Arctic),* **WSB** *(West Siberia),* **ESB** *(East Siberia),* **RFE** *(Russian Far East),* **WCA** *(West Central Asia),* **ECA** *(East Central Asia),* **TIB** *(Tibetan Plateau),* **EAS** *(East Asia),* **ARP** *(Arabian Peninsula),* **SAS** *(South Asia),* **SEA** *(South East Asia),* **Australasia: NAU** *(Northern Australia),* **CAU** *(Central Australia),* **EAU** *(Eastern Australia),* **SAU** *(Southern Australia),* **NZ** *(New Zealand),* **Small Islands: CAR** *(Caribbean),* **PAC** *(Pacific Small Islands)*

Figure SPM.3 | Synthesis of assessed observed and attributable regional changes

The IPCC AR6 WGI inhabited regions are displayed as **hexagons** with identical size in their approximate geographical location (see legend for regional acronyms). All assessments are made for each region as a whole and for the 1950s to the present. Assessments made on different time scales or more local spatial scales might differ from what is shown in the figure. The **colours** in each panel represent the four outcomes of the assessment on observed changes. Striped hexagons (white and light-grey) are used where there is *low agreement* in the type of change for the region as a whole, and grey hexagons are used when there is limited data and/or literature that prevents an assessment of the region as a whole. Other colours indicate at least *medium confidence* in the observed change. The **confidence level** for the human influence on these observed changes is based on assessing trend detection and attribution and event attribution literature, and it is indicated by the number of dots: three dots for *high confidence*, two dots for *medium confidence* and one dot for *low confidence* (single, filled dot: limited agreement; single, empty dot: limited evidence).

Panel (a) For hot extremes, the evidence is mostly drawn from changes in metrics based on daily maximum temperatures; regional studies using other indices (heatwave duration, frequency and intensity) are used in addition. Red hexagons indicate regions where there is at least *medium confidence* in an observed increase in hot extremes.

Panel (b) For heavy precipitation, the evidence is mostly drawn from changes in indices based on one-day or five-day precipitation amounts using global and regional studies. Green hexagons indicate regions where there is at least *medium confidence* in an observed increase in heavy precipitation.

Panel (c) Agricultural and ecological droughts are assessed based on observed and simulated changes in total column soil moisture, complemented by evidence on changes in surface soil moisture, water balance (precipitation minus evapotranspiration) and indices driven by precipitation and atmospheric evaporative demand. Yellow hexagons indicate regions where there is at least *medium confidence* in an observed increase in this type of drought, and green hexagons indicate regions where there is at least *medium confidence* in an observed decrease in agricultural and ecological drought.

For all regions, Table TS.5 shows a broader range of observed changes besides the ones shown in this figure. Note that Southern South America (SSA) is the only region that does not display observed changes in the metrics shown in this figure, but is affected by observed increases in mean temperature, decreases in frost and increases in marine heatwaves.

{11.9, Atlas 1.3.3, Figure Atlas.2, Table TS.5; Box TS.10, Figure 1}

A.4 Improved knowledge of climate processes, paleoclimate evidence and the response of the climate system to increasing radiative forcing gives a best estimate of equilibrium climate sensitivity of 3°C, with a narrower range compared to AR5. {2.2, 7.3, 7.4, 7.5, Box 7.2, 9.4, 9.5, 9.6, Cross-Chapter Box 9.1}

A.4.1 Human-caused radiative forcing of 2.72 [1.96 to 3.48] W m^{-2} in 2019 relative to 1750 has warmed the climate system. This warming is mainly due to increased GHG concentrations, partly reduced by cooling due to increased aerosol concentrations. The radiative forcing has increased by 0.43 W m^{-2} (19%) relative to AR5, of which 0.34 W m^{-2} is due to the increase in GHG concentrations since 2011. The remainder is due to improved scientific understanding and changes in the assessment of aerosol forcing, which include decreases in concentration and improvement in its calculation (*high confidence*).
{2.2, 7.3, TS.2.2, TS.3.1}

A.4.2 Human-caused net positive radiative forcing causes an accumulation of additional energy (heating) in the climate system, partly reduced by increased energy loss to space in response to surface warming. The observed average rate of heating of the climate system increased from 0.50 [0.32 to 0.69] W m^{-2} for the period 1971–2006[19] to 0.79 [0.52 to 1.06] W m^{-2} for the period 2006–2018[20] (*high confidence*). Ocean warming accounted for 91% of the heating in the climate system, with land warming, ice loss and atmospheric warming accounting for about 5%, 3% and 1%, respectively (*high confidence*).
{7.2, Box 7.2, TS.3.1}

A.4.3 Heating of the climate system has caused global mean sea level rise through ice loss on land and thermal expansion from ocean warming. Thermal expansion explained 50% of sea level rise during 1971–2018, while ice loss from glaciers contributed 22%, ice sheets 20% and changes in land-water storage 8%. The rate of ice-sheet loss increased by a factor of four between 1992–1999 and 2010–2019. Together, ice-sheet and glacier mass loss were the dominant contributors to global mean sea level rise during 2006–2018 (*high confidence*).
{9.4, 9.5, 9.6, Cross-Chapter Box 9.1}

A.4.4 The equilibrium climate sensitivity is an important quantity used to estimate how the climate responds to radiative forcing. Based on multiple lines of evidence,[21] the *very likely* range of equilibrium climate sensitivity is between 2°C (*high confidence*) and 5°C (*medium confidence*). The AR6 assessed best estimate is 3°C with a *likely* range of 2.5°C to 4°C (*high confidence*), compared to 1.5°C to 4.5°C in AR5, which did not provide a best estimate.
{7.4, 7.5, TS.3.2}

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19 Cumulative energy increase of 282 [177 to 387] ZJ over 1971–2006 (1 ZJ = 10^{21} joules).

20 Cumulative energy increase of 152 [100 to 205] ZJ over 2006–2018.

21 Understanding of climate processes, the instrumental record, paleoclimates and model-based emergent constraints (Glossary).

SPM

B. Possible Climate Futures

A set of five new illustrative emissions scenarios is considered consistently across this Report to explore the climate response to a broader range of greenhouse gas (GHG), land-use and air pollutant futures than assessed in AR5. This set of scenarios drives climate model projections of changes in the climate system. These projections account for solar activity and background forcing from volcanoes. Results over the 21st century are provided for the near term (2021–2040), mid-term (2041–2060) and long term (2081–2100) relative to 1850–1900, unless otherwise stated.

Box SPM.1 | Scenarios, Climate Models and Projections

Box SPM.1.1: This Report assesses the climate response to five illustrative scenarios that cover the range of possible future development of anthropogenic drivers of climate change found in the literature. They start in 2015, and include scenarios[22] with high and very high GHG emissions (SSP3-7.0 and SSP5-8.5) and CO_2 emissions that roughly double from current levels by 2100 and 2050, respectively, scenarios with intermediate GHG emissions (SSP2-4.5) and CO_2 emissions remaining around current levels until the middle of the century, and scenarios with very low and low GHG emissions and CO_2 emissions declining to net zero around or after 2050, followed by varying levels of net negative CO_2 emissions[23] (SSP1-1.9 and SSP1-2.6), as illustrated in Figure SPM.4. Emissions vary between scenarios depending on socio-economic assumptions, levels of climate change mitigation and, for aerosols and non-methane ozone precursors, air pollution controls. Alternative assumptions may result in similar emissions and climate responses, but the socio-economic assumptions and the feasibility or likelihood of individual scenarios are not part of the assessment.
{1.6, Cross-Chapter Box 1.4, TS.1.3} (Figure SPM.4)

Box SPM.1.2: This Report assesses results from climate models participating in the Coupled Model Intercomparison Project Phase 6 (CMIP6) of the World Climate Research Programme. These models include new and better representations of physical, chemical and biological processes, as well as higher resolution, compared to climate models considered in previous IPCC assessment reports. This has improved the simulation of the recent mean state of most large-scale indicators of climate change and many other aspects across the climate system. Some differences from observations remain, for example in regional precipitation patterns. The CMIP6 historical simulations assessed in this Report have an ensemble mean global surface temperature change within 0.2°C of the observations over most of the historical period, and observed warming is within the *very likely* range of the CMIP6 ensemble. However, some CMIP6 models simulate a warming that is either above or below the assessed *very likely* range of observed warming.
{1.5, Cross-Chapter Box 2.2, 3.3, 3.8, TS.1.2, Cross-Section Box TS.1} (Figure SPM.1b, Figure SPM.2)

Box SPM.1.3: The CMIP6 models considered in this Report have a wider range of climate sensitivity than in CMIP5 models and the AR6 assessed *very likely* range, which is based on multiple lines of evidence. These CMIP6 models also show a higher average climate sensitivity than CMIP5 and the AR6 assessed best estimate. The higher CMIP6 climate sensitivity values compared to CMIP5 can be traced to an amplifying cloud feedback that is larger in CMIP6 by about 20%.
{Box 7.1, 7.3, 7.4, 7.5, TS.3.2}

Box SPM.1.4: For the first time in an IPCC report, assessed future changes in global surface temperature, ocean warming and sea level are constructed by combining multi-model projections with observational constraints based on past simulated warming, as well as the AR6 assessment of climate sensitivity. For other quantities, such robust methods do not yet exist to constrain the projections. Nevertheless, robust projected geographical patterns of many variables can be identified at a given level of global warming, common to all scenarios considered and independent of timing when the global warming level is reached.
{1.6, 4.3, 4.6, Box 4.1, 7.5, 9.2, 9.6, Cross-Chapter Box 11.1, Cross-Section Box TS.1}

22 Throughout this Report, the five illustrative scenarios are referred to as SSPx-y, where 'SSPx' refers to the Shared Socio-economic Pathway or 'SSP' describing the socio-economic trends underlying the scenario, and 'y' refers to the approximate level of radiative forcing (in watts per square metre, or W m^{-2}) resulting from the scenario in the year 2100. A detailed comparison to scenarios used in earlier IPCC reports is provided in Section TS.1.3, and Sections 1.6 and 4.6. The SSPs that underlie the specific forcing scenarios used to drive climate models are not assessed by WGI. Rather, the SSPx-y labelling ensures traceability to the underlying literature in which specific forcing pathways are used as input to the climate models. IPCC is neutral with regard to the assumptions underlying the SSPs, which do not cover all possible scenarios. Alternative scenarios may be considered or developed.

23 Net negative CO_2 emissions are reached when anthropogenic removals of CO_2 exceed anthropogenic emissions (Glossary).

Box SPM.1 (continued)

Future emissions cause future additional warming, with total warming dominated by past and future CO_2 emissions

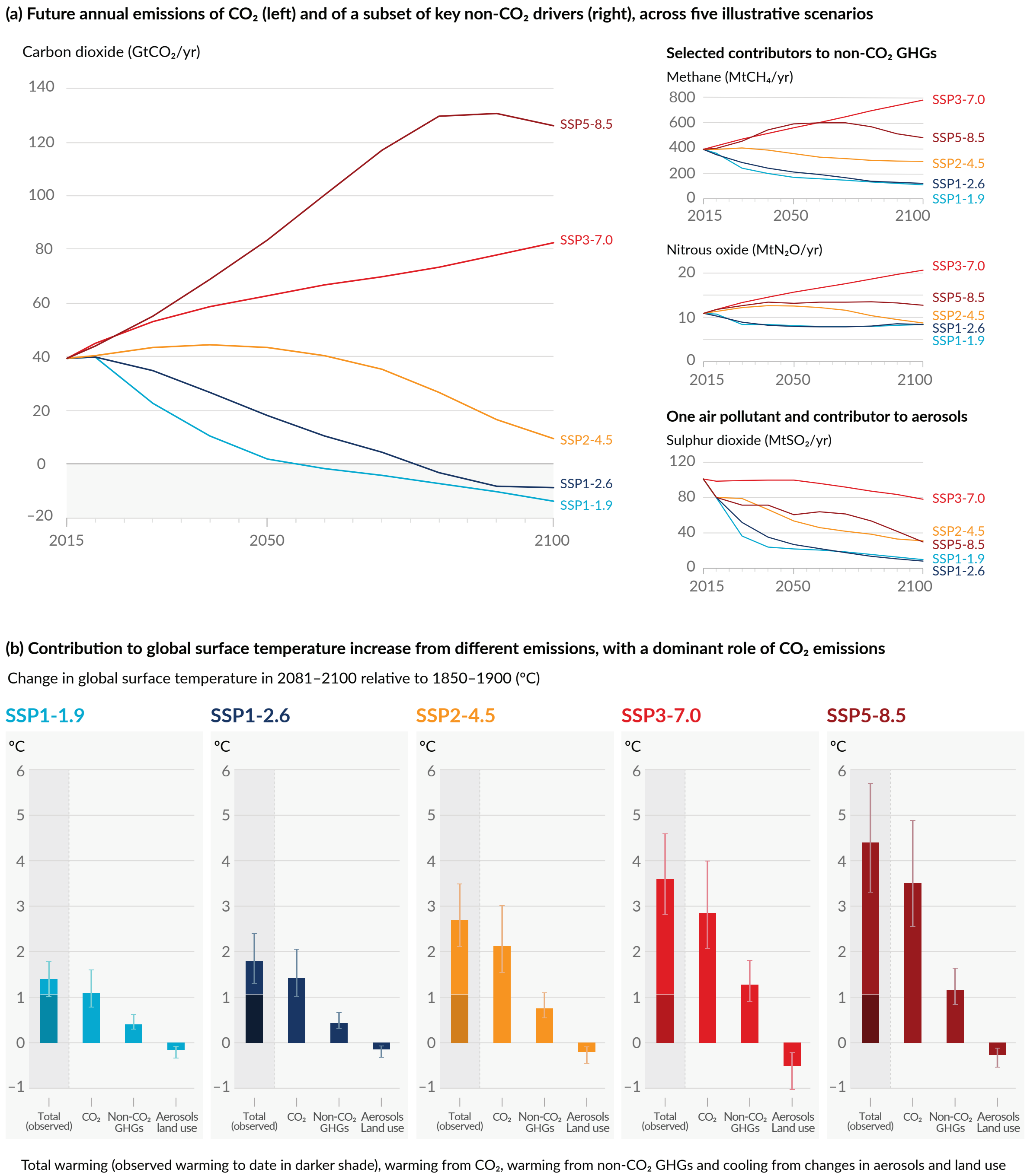

Figure SPM.4 | Future anthropogenic emissions of key drivers of climate change and warming contributions by groups of drivers for the five illustrative scenarios used in this report

The five scenarios are SSP1-1.9, SSP1-2.6, SSP2-4.5, SSP3-7.0 and SSP5-8.5.

Panel (a) Annual anthropogenic (human-caused) emissions over the 2015–2100 period. Shown are emissions trajectories for carbon dioxide (CO_2) from all sectors ($GtCO_2/yr$) (left graph) and for a subset of three key non-CO_2 drivers considered in the scenarios: methane (CH_4, $MtCH_4/yr$, top-right graph); nitrous oxide (N_2O, MtN_2O/yr, middle-right graph); and sulphur dioxide (SO_2, $MtSO_2/yr$, bottom-right graph, contributing to anthropogenic aerosols in panel (b).

Panel (b) Warming contributions by groups of anthropogenic drivers and by scenario are shown as the change in global surface temperature (°C) in 2081–2100 relative to 1850–1900, with indication of the observed warming to date. Bars and whiskers represent median values and the *very likely* range, respectively. Within each scenario bar plot, the bars represent: total global warming (°C; 'total' bar) (see Table SPM.1); warming contributions (°C) from changes in CO_2 ('CO_2' bar) and from non-CO_2 greenhouse gases (GHGs; 'non-CO_2 GHGs' bar: comprising well-mixed greenhouse gases and ozone); and net cooling from other anthropogenic drivers ('aerosols and land use' bar: anthropogenic aerosols, changes in reflectance due to land-use and irrigation changes, and contrails from aviation) (see Figure SPM.2, panel c, for the warming contributions to date for individual drivers). The best estimate for observed warming in 2010–2019 relative to 1850–1900 (see Figure SPM.2, panel a) is indicated in the darker column in the 'total' bar. Warming contributions in panel (b) are calculated as explained in Table SPM.1 for the total bar. For the other bars, the contribution by groups of drivers is calculated with a physical climate emulator of global surface temperature that relies on climate sensitivity and radiative forcing assessments.

{Cross-Chapter Box 1.4; 4.6; Figure 4.35; 6.7; Figures 6.18, 6.22 and 6.24; 7.3; Cross-Chapter Box 7.1; Figure 7.7; Box TS.7; Figures TS.4 and TS.15}

B.1 Global surface temperature will continue to increase until at least mid-century under all emissions scenarios considered. Global warming of 1.5°C and 2°C will be exceeded during the 21st century unless deep reductions in CO_2 and other greenhouse gas emissions occur in the coming decades.
{2.3, Cross-Chapter Box 2.3, Cross-Chapter Box 2.4, 4.3, 4.4, 4.5} (Figure SPM.1, Figure SPM.4, Figure SPM.8, Table SPM.1, Box SPM.1)

B.1.1 Compared to 1850–1900, global surface temperature averaged over 2081–2100 is *very likely* to be higher by 1.0°C to 1.8°C under the very low GHG emissions scenario considered (SSP1-1.9), by 2.1°C to 3.5°C in the intermediate GHG emissions scenario (SSP2-4.5) and by 3.3°C to 5.7°C under the very high GHG emissions scenario (SSP5-8.5).[24] The last time global surface temperature was sustained at or above 2.5°C higher than 1850–1900 was over 3 million years ago (*medium confidence*).
{2.3, Cross-Chapter Box 2.4, 4.3, 4.5, Box TS.2, Box TS.4, Cross-Section Box TS.1} (Table SPM.1)

Table SPM.1 | Changes in global surface temperature, which are assessed based on multiple lines of evidence, for selected 20-year time periods and the five illustrative emissions scenarios considered. Temperature differences relative to the average global surface temperature of the period 1850–1900 are reported in °C. This includes the revised assessment of observed historical warming for the AR5 reference period 1986–2005, which in AR6 is higher by 0.08 [–0.01 to +0.12] °C than in AR5 (see footnote 10). Changes relative to the recent reference period 1995–2014 may be calculated approximately by subtracting 0.85°C, the best estimate of the observed warming from 1850–1900 to 1995–2014.
{Cross-Chapter Box 2.3, 4.3, 4.4, Cross-Section Box TS.1}

	Near term, 2021–2040		Mid-term, 2041–2060		Long term, 2081–2100	
Scenario	Best estimate (°C)	*Very likely* range (°C)	Best estimate (°C)	*Very likely* range (°C)	Best estimate (°C)	*Very likely* range (°C)
SSP1-1.9	1.5	1.2 to 1.7	1.6	1.2 to 2.0	1.4	1.0 to 1.8
SSP1-2.6	1.5	1.2 to 1.8	1.7	1.3 to 2.2	1.8	1.3 to 2.4
SSP2-4.5	1.5	1.2 to 1.8	2.0	1.6 to 2.5	2.7	2.1 to 3.5
SSP3-7.0	1.5	1.2 to 1.8	2.1	1.7 to 2.6	3.6	2.8 to 4.6
SSP5-8.5	1.6	1.3 to 1.9	2.4	1.9 to 3.0	4.4	3.3 to 5.7

B.1.2 Based on the assessment of multiple lines of evidence, global warming of 2°C, relative to 1850–1900, would be exceeded during the 21st century under the high and very high GHG emissions scenarios considered in this report (SSP3-7.0 and SSP5-8.5, respectively). Global warming of 2°C would *extremely likely* be exceeded in the intermediate GHG emissions scenario (SSP2-4.5). Under the very low and low GHG emissions scenarios, global warming of 2°C is *extremely unlikely* to be exceeded (SSP1-1.9) or *unlikely* to be exceeded (SSP1-2.6).[25] Crossing the 2°C global warming level in the mid-term period (2041–2060) is *very likely* to occur under the very high GHG emissions scenario (SSP5-8.5), *likely* to occur under the high GHG emissions scenario (SSP3-7.0), and *more likely than not* to occur in the intermediate GHG emissions scenario (SSP2-4.5).[26]
{4.3, Cross-Section Box TS.1} (Table SPM.1, Figure SPM.4, Box SPM.1)

24 Changes in global surface temperature are reported as running 20-year averages, unless stated otherwise.

25 SSP1-1.9 and SSP1-2.6 are scenarios that start in 2015 and have very low and low GHG emissions, respectively, and CO_2 emissions declining to net zero around or after 2050, followed by varying levels of net negative CO_2 emissions.

26 Crossing is defined here as having the assessed global surface temperature change, averaged over a 20-year period, exceed a particular global warming level.

B.1.3 Global warming of 1.5°C relative to 1850–1900 would be exceeded during the 21st century under the intermediate, high and very high GHG emissions scenarios considered in this report (SSP2-4.5, SSP3-7.0 and SSP5-8.5, respectively). Under the five illustrative scenarios, in the near term (2021–2040), the 1.5°C global warming level is *very likely* to be exceeded under the very high GHG emissions scenario (SSP5-8.5), *likely* to be exceeded under the intermediate and high GHG emissions scenarios (SSP2-4.5 and SSP3-7.0), *more likely than not* to be exceeded under the low GHG emissions scenario (SSP1-2.6) and *more likely than not* to be reached under the very low GHG emissions scenario (SSP1-1.9).[27] Furthermore, for the very low GHG emissions scenario (SSP1-1.9), it is *more likely than not* that global surface temperature would decline back to below 1.5°C toward the end of the 21st century, with a temporary overshoot of no more than 0.1°C above 1.5°C global warming.
{4.3, Cross-Section Box TS.1} (Table SPM.1, Figure SPM.4)

B.1.4 Global surface temperature in any single year can vary above or below the long-term human-induced trend, due to substantial natural variability.[28] The occurrence of individual years with global surface temperature change above a certain level, for example 1.5°C or 2°C, relative to 1850–1900 does not imply that this global warming level has been reached.[29]
{Cross-Chapter Box 2.3, 4.3, 4.4, Box 4.1, Cross-Section Box TS.1} (Table SPM.1, Figure SPM.1, Figure SPM.8)

B.2 Many changes in the climate system become larger in direct relation to increasing global warming. They include increases in the frequency and intensity of hot extremes, marine heatwaves, heavy precipitation, and, in some regions, agricultural and ecological droughts; an increase in the proportion of intense tropical cyclones; and reductions in Arctic sea ice, snow cover and permafrost.
{4.3, 4.5, 4.6, 7.4, 8.2, 8.4, Box 8.2, 9.3, 9.5, Box 9.2, 11.1, 11.2, 11.3, 11.4, 11.6, 11.7, 11.9, Cross-Chapter Box 11.1, 12.4, 12.5, Cross-Chapter Box 12.1, Atlas.4, Atlas.5, Atlas.6, Atlas.7, Atlas.8, Atlas.9, Atlas.10, Atlas.11} (Figure SPM.5, Figure SPM.6, Figure SPM.8)

B.2.1 It is *virtually certain* that the land surface will continue to warm more than the ocean surface (*likely* 1.4 to 1.7 times more). It is *virtually certain* that the Arctic will continue to warm more than global surface temperature, with *high confidence* above two times the rate of global warming.
{2.3, 4.3, 4.5, 4.6, 7.4, 11.1, 11.3, 11.9, 12.4, 12.5, Cross-Chapter Box 12.1, Atlas.4, Atlas.5, Atlas.6, Atlas.7, Atlas.8, Atlas.9, Atlas.10, Atlas.11, Cross-Section Box TS.1, TS.2.6} (Figure SPM.5)

B.2.2 With every additional increment of global warming, changes in extremes continue to become larger. For example, every additional 0.5°C of global warming causes clearly discernible increases in the intensity and frequency of hot extremes, including heatwaves (*very likely*), and heavy precipitation (*high confidence*), as well as agricultural and ecological droughts[30] in some regions (*high confidence*). Discernible changes in intensity and frequency of meteorological droughts, with more regions showing increases than decreases, are seen in some regions for every additional 0.5°C of global warming (*medium confidence*). Increases in frequency and intensity of hydrological droughts become larger with increasing global warming in some regions (*medium confidence*). There will be an increasing occurrence of some extreme events unprecedented in the observational record with additional global warming, even at 1.5°C of global warming. Projected percentage changes in frequency are larger for rarer events (*high confidence*).
{8.2, 11.2, 11.3, 11.4, 11.6, 11.9, Cross-Chapter Box 11.1, Cross-Chapter Box 12.1, TS.2.6} (Figure SPM.5, Figure SPM.6)

B.2.3 Some mid-latitude and semi-arid regions, and the South American Monsoon region, are projected to see the highest increase in the temperature of the hottest days, at about 1.5 to 2 times the rate of global warming (*high confidence*). The Arctic is projected to experience the highest increase in the temperature of the coldest days, at about three times the rate of global warming (*high confidence*). With additional global warming, the frequency of marine heatwaves will continue to increase (*high confidence*), particularly in the tropical ocean and the Arctic (*medium confidence*).
{Box 9.2, 11.1, 11.3, 11.9, Cross-Chapter Box 11.1, Cross-Chapter Box 12.1, 12.4, TS.2.4, TS.2.6} (Figure SPM.6)

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27 The AR6 assessment of when a given global warming level is first exceeded benefits from the consideration of the illustrative scenarios, the multiple lines of evidence entering the assessment of future global surface temperature response to radiative forcing, and the improved estimate of historical warming. The AR6 assessment is thus not directly comparable to the SR1.5 SPM, which reported *likely* reaching 1.5°C global warming between 2030 and 2052, from a simple linear extrapolation of warming rates of the recent past. When considering scenarios similar to SSP1-1.9 instead of linear extrapolation, the SR1.5 estimate of when 1.5°C global warming is first exceeded is close to the best estimate reported here.

28 Natural variability refers to climatic fluctuations that occur without any human influence, that is, internal variability combined with the response to external natural factors such as volcanic eruptions, changes in solar activity and, on longer time scales, orbital effects and plate tectonics (Glossary).

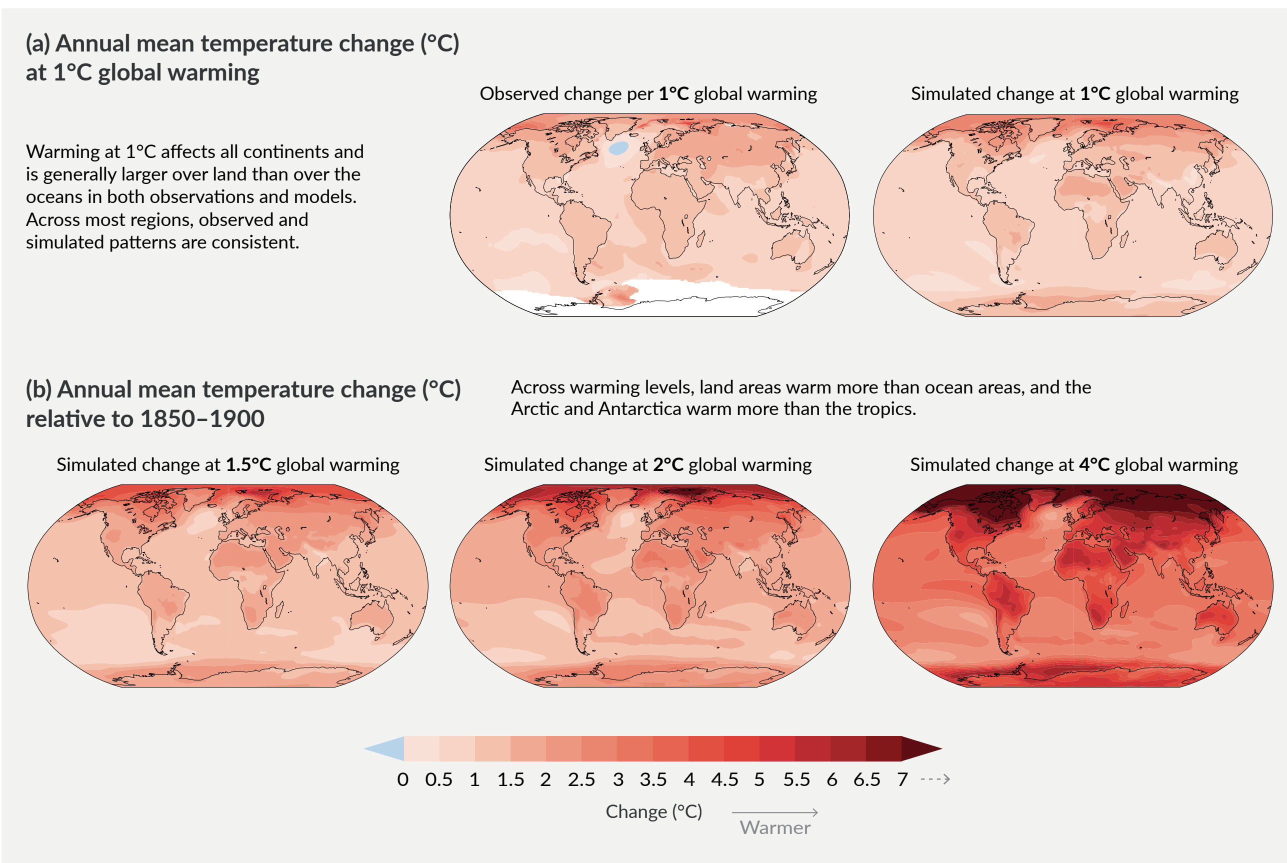
29 The internal variability in any single year is estimated to be about ±0.25°C (5–95% range, *high confidence*).

30 Projected changes in agricultural and ecological droughts are primarily assessed based on total column soil moisture. See footnote 15 for definition and relation to precipitation and evapotranspiration.

B.2.4 It is *very likely* that heavy precipitation events will intensify and become more frequent in most regions with additional global warming. At the global scale, extreme daily precipitation events are projected to intensify by about 7% for each 1°C of global warming (*high confidence*). The proportion of intense tropical cyclones (Category 4–5) and peak wind speeds of the most intense tropical cyclones are projected to increase at the global scale with increasing global warming (*high confidence*). {8.2, 11.4, 11.7, 11.9, Cross-Chapter Box 11.1, Box TS.6, TS.4.3.1} (Figure SPM.5, Figure SPM.6)

B.2.5 Additional warming is projected to further amplify permafrost thawing and loss of seasonal snow cover, of land ice and of Arctic sea ice (*high confidence*). The Arctic is *likely* to be practically sea ice-free in September[31] at least once before 2050 under the five illustrative scenarios considered in this report, with more frequent occurrences for higher warming levels. There is *low confidence* in the projected decrease of Antarctic sea ice.
{4.3, 4.5, 7.4, 8.2, 8.4, Box 8.2, 9.3, 9.5, 12.4, Cross-Chapter Box 12.1, Atlas.5, Atlas.6, Atlas.8, Atlas.9, Atlas.11, TS.2.5} (Figure SPM.8)

With every increment of global warming, changes get larger in regional mean temperature, precipitation and soil moisture



31 Monthly average sea ice area of less than 1 million km^2, which is about 15% of the average September sea ice area observed in 1979–1988.

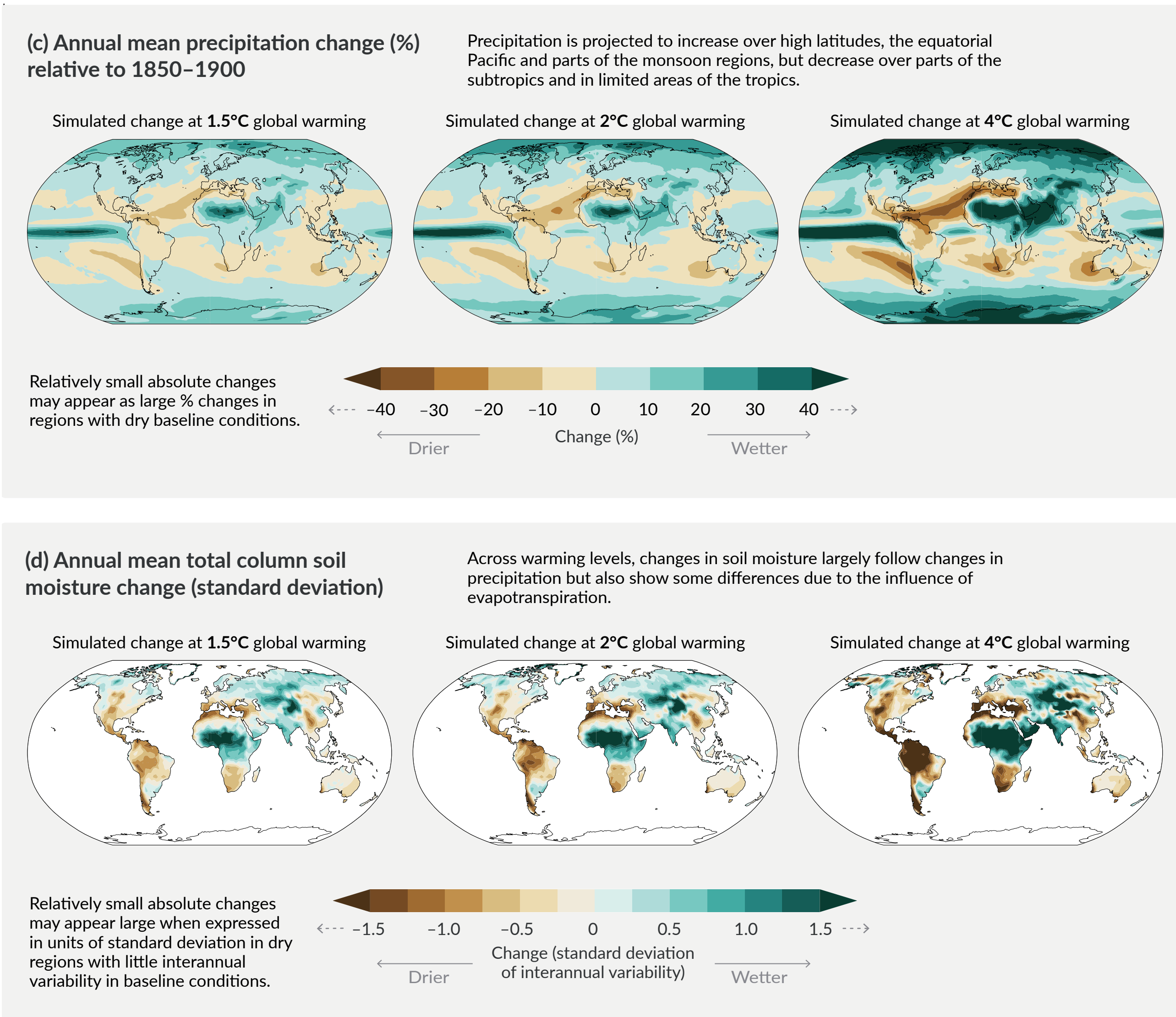


Figure SPM.5 | Changes in annual mean surface temperature, precipitation, and soil moisture

Panel (a) Comparison of observed and simulated annual mean surface temperature change. The **left map** shows the observed changes in annual mean surface temperature in the period 1850–2020 per °C of global warming (°C). The local (i.e., grid point) observed annual mean surface temperature changes are linearly regressed against the global surface temperature in the period 1850–2020. Observed temperature data are from Berkeley Earth, the dataset with the largest coverage and highest horizontal resolution. Linear regression is applied to all years for which data at the corresponding grid point is available. The regression method was used to take into account the complete observational time series and thereby reduce the role of internal variability at the grid point level. White indicates areas where time coverage was 100 years or less and thereby too short to calculate a reliable linear regression. The **right map** is based on model simulations and shows change in annual multi-model mean simulated temperatures at a global warming level of 1°C (20-year mean global surface temperature change relative to 1850–1900). The triangles at each end of the colour bar indicate out-of-bound values, that is, values above or below the given limits.

Panel (b) Simulated annual mean temperature change (°C), panel (c) precipitation change (%), and panel (d) total column soil moisture change (standard deviation of interannual variability) at global warming levels of 1.5°C, 2°C and 4°C (20-year mean global surface temperature change relative to 1850–1900). Simulated changes correspond to Coupled Model Intercomparison Project Phase 6 (CMIP6) multi-model mean change (median change for soil moisture) at the corresponding global warming level, that is, the same method as for the right map in panel (a).

In **panel (c)**, high positive percentage changes in dry regions may correspond to small absolute changes. In **panel (d)**, the unit is the standard deviation of interannual variability in soil moisture during 1850–1900. Standard deviation is a widely used metric in characterizing drought severity. A projected reduction in mean soil moisture by one standard deviation corresponds to soil moisture conditions typical of droughts that occurred about once every six years during 1850–1900. In panel (d), large changes in dry regions with little interannual variability in the baseline conditions can correspond to small absolute change. The triangles at each end of the colour bars indicate out-of-bound values, that is, values above or below the given limits. Results from all models reaching the corresponding warming level in any of the five illustrative scenarios (SSP1-1.9, SSP1-2.6, SSP2-4.5, SSP3-7.0 and SSP5-8.5) are averaged. Maps of annual mean temperature and precipitation changes at a global warming level of 3°C are available in Figure 4.31 and Figure 4.32 in Section 4.6. Corresponding maps of panels (b), (c) and (d), including hatching to indicate the level of model agreement at grid-cell level, are found in Figures 4.31, 4.32 and 11.19, respectively; as highlighted in Cross-Chapter Box Atlas.1, grid-cell level hatching is not informative for larger spatial scales (e.g., over AR6 reference regions) where the aggregated signals are less affected by small-scale variability, leading to an increase in robustness.

{Figure 1.14, 4.6.1, Cross-Chapter Box 11.1, Cross-Chapter Box Atlas.1, TS.1.3.2, Figures TS.3 and TS.5}

Projected changes in extremes are larger in frequency and intensity with every additional increment of global warming

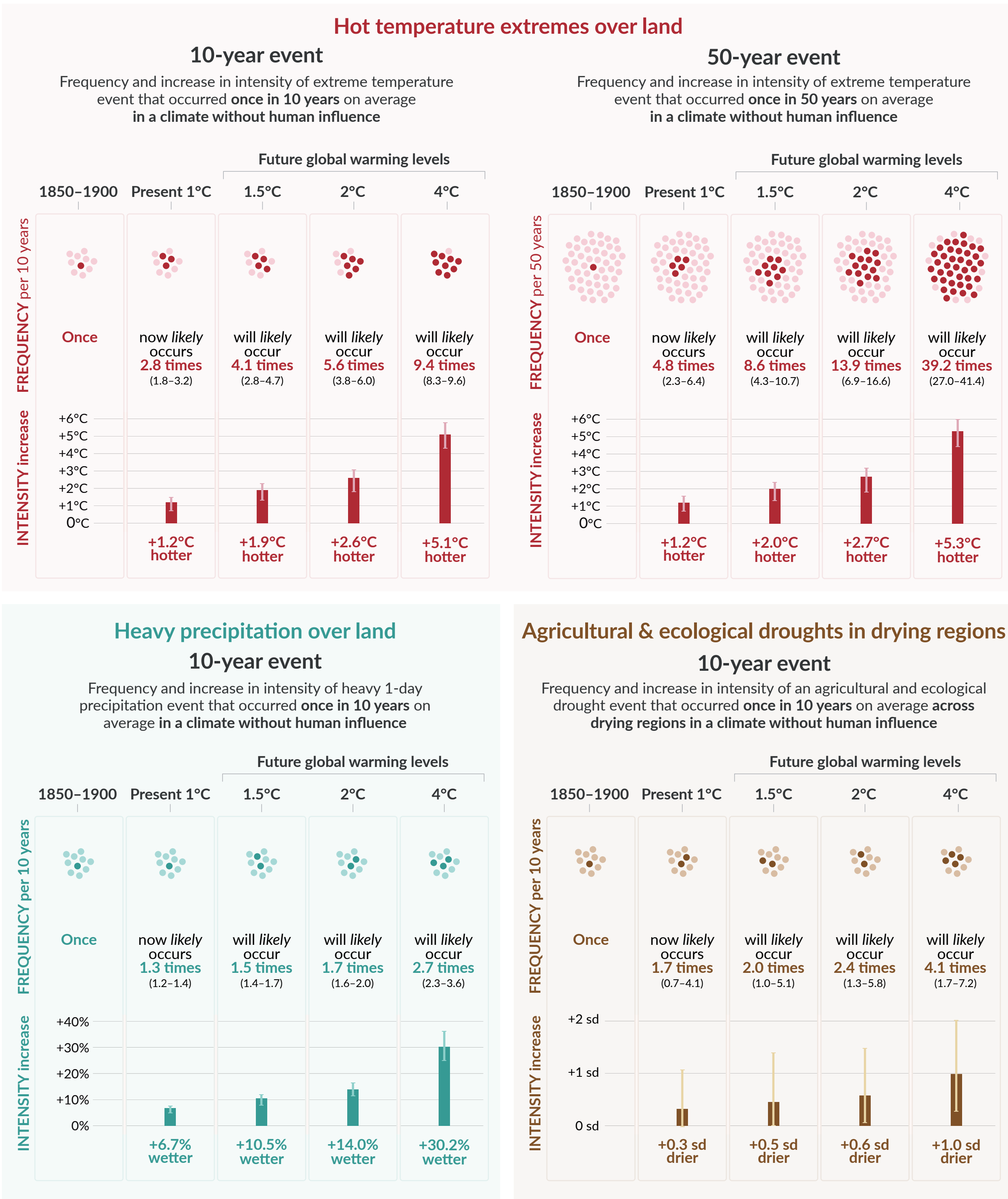


Figure SPM.6 | Projected changes in the intensity and frequency of hot temperature extremes over land, extreme precipitation over land, and agricultural and ecological droughts in drying regions

Projected changes are shown at global warming levels of 1°C, 1.5°C, 2°C, and 4°C and are relative to 1850–1900,[9] representing a climate without human influence. The figure depicts frequencies and increases in intensity of 10- or 50-year extreme events from the base period (1850–1900) under different global warming levels.

Hot temperature extremes are defined as the daily maximum temperatures over land that were exceeded on average once in a decade (10-year event) or once in 50 years (50-year event) during the 1850–1900 reference period. **Extreme precipitation events** are defined as the daily precipitation amount over land that was exceeded on average once in a decade during the 1850–1900 reference period. **Agricultural and ecological drought events** are defined as the annual average of total column soil moisture below the 10th percentile of the 1850–1900 base period. These extremes are defined on model grid box scale. For hot temperature extremes and extreme precipitation, results are shown for the global land. For agricultural and ecological drought, results are shown for drying regions only, which correspond to the AR6 regions in which there is at least *medium confidence* in a projected increase in agricultural and ecological droughts at the 2°C warming level compared to the 1850–1900 base period in the Coupled Model Intercomparison Project Phase 6 (CMIP6). These regions include Western North America, Central North America, Northern Central America, Southern Central America, Caribbean, Northern South America, North-Eastern South America, South American Monsoon, South-Western South America, Southern South America, Western and Central Europe, Mediterranean, West Southern Africa, East Southern Africa, Madagascar, Eastern Australia, and Southern Australia (Caribbean is not included in the calculation of the figure because of the too-small number of full land grid cells). The non-drying regions do not show an overall increase or decrease in drought severity. Projections of changes in agricultural and ecological droughts in the CMIP Phase 5 (CMIP5) multi-model ensemble differ from those in CMIP6 in some regions, including in parts of Africa and Asia. Assessments of projected changes in meteorological and hydrological droughts are provided in Chapter 11.

In the **'frequency' section**, each year is represented by a dot. The dark dots indicate years in which the extreme threshold is exceeded, while light dots are years when the threshold is not exceeded. Values correspond to the medians (in bold) and their respective 5–95% range based on the multi-model ensemble from simulations of CMIP6 under different Shared Socio-economic Pathway scenarios. For consistency, the number of dark dots is based on the rounded-up median. In the **'intensity' section**, medians and their 5–95% range, also based on the multi-model ensemble from simulations of CMIP6, are displayed as dark and light bars, respectively. Changes in the intensity of hot temperature extremes and extreme precipitation are expressed as degree Celsius and percentage. As for agricultural and ecological drought, intensity changes are expressed as fractions of standard deviation of annual soil moisture.

{11.1; 11.3; 11.4; 11.6; 11.9; Figures 11.12, 11.15, 11.6, 11.7, and 11.18}

B.3 Continued global warming is projected to further intensify the global water cycle, including its variability, global monsoon precipitation and the severity of wet and dry events.
{4.3, 4.4, 4.5, 4.6, 8.2, 8.3, 8.4, 8.5, Box 8.2, 11.4, 11.6, 11.9, 12.4, Atlas.3} (Figure SPM.5, Figure SPM.6)

B.3.1 There is strengthened evidence since AR5 that the global water cycle will continue to intensify as global temperatures rise (*high confidence*), with precipitation and surface water flows projected to become more variable over most land regions within seasons (*high confidence*) and from year to year (*medium confidence*). The average annual global land precipitation is projected to increase by 0–5% under the very low GHG emissions scenario (SSP1-1.9), 1.5–8% for the intermediate GHG emissions scenario (SSP2-4.5) and 1–13% under the very high GHG emissions scenario (SSP5-8.5) by 2081–2100 relative to 1995–2014 (*likely* ranges). Precipitation is projected to increase over high latitudes, the equatorial Pacific and parts of the monsoon regions, but decrease over parts of the subtropics and limited areas in the tropics in SSP2-4.5, SSP3-7.0 and SSP5-8.5 (*very likely*). The portion of the global land experiencing detectable increases or decreases in seasonal mean precipitation is projected to increase (*medium confidence*). There is *high confidence* in an earlier onset of spring snowmelt, with higher peak flows at the expense of summer flows in snow-dominated regions globally.
{4.3, 4.5, 4.6, 8.2, 8.4, Atlas.3, TS.2.6, TS.4.3, Box TS.6} (Figure SPM.5)

B.3.2 A warmer climate will intensify very wet and very dry weather and climate events and seasons, with implications for flooding or drought (*high confidence*), but the location and frequency of these events depend on projected changes in regional atmospheric circulation, including monsoons and mid-latitude storm tracks. It is *very likely* that rainfall variability related to the El Niño–Southern Oscillation is projected to be amplified by the second half of the 21st century in the SSP2-4.5, SSP3-7.0 and SSP5-8.5 scenarios.
{4.3, 4.5, 4.6, 8.2, 8.4, 8.5, 11.4, 11.6, 11.9, 12.4, TS.2.6, TS.4.2, Box TS.6} (Figure SPM.5, Figure SPM.6)

B.3.3 Monsoon precipitation is projected to increase in the mid- to long term at the global scale, particularly over South and South East Asia, East Asia and West Africa apart from the far west Sahel (*high confidence*). The monsoon season is projected to have a delayed onset over North and South America and West Africa (*high confidence*) and a delayed retreat over West Africa (*medium confidence*).
{4.4, 4.5, 8.2, 8.3, 8.4, Box 8.2, Box TS.13}

B.3.4 A projected southward shift and intensification of Southern Hemisphere summer mid-latitude storm tracks and associated precipitation is *likely* in the long term under high GHG emissions scenarios (SSP3-7.0, SSP5-8.5), but in the near term the effect of stratospheric ozone recovery counteracts these changes (*high confidence*). There is *medium confidence* in a continued poleward shift of storms and their precipitation in the North Pacific, while there is *low confidence* in projected changes in the North Atlantic storm tracks.
{4.4, 4.5, 8.4, TS.2.3, TS.4.2}

B.4 Under scenarios with increasing CO_2 emissions, the ocean and land carbon sinks are projected to be less effective at slowing the accumulation of CO_2 in the atmosphere.
{4.3, 5.2, 5.4, 5.5, 5.6} (Figure SPM.7)

B.4.1 While natural land and ocean carbon sinks are projected to take up, in absolute terms, a progressively larger amount of CO_2 under higher compared to lower CO_2 emissions scenarios, they become less effective, that is, the proportion of emissions taken up by land and ocean decrease with increasing cumulative CO_2 emissions. This is projected to result in a higher proportion of emitted CO_2 remaining in the atmosphere (*high confidence*).
{5.2, 5.4, Box TS.5} (Figure SPM.7)

B.4.2 Based on model projections, under the intermediate GHG emissions scenario that stabilizes atmospheric CO_2 concentrations this century (SSP2-4.5), the rates of CO_2 taken up by the land and ocean are projected to decrease in the second half of the 21st century (*high confidence*). Under the very low and low GHG emissions scenarios (SSP1-1.9, SSP1-2.6), where CO_2 concentrations peak and decline during the 21st century, the land and ocean begin to take up less carbon in response to declining atmospheric CO_2 concentrations (*high confidence*) and turn into a weak net source by 2100 under SSP1-1.9 (*medium confidence*). It is *very unlikely* that the combined global land and ocean sink will turn into a source by 2100 under scenarios without net negative emissions (SSP2-4.5, SSP3-7.0, SSP5-8.5).[32]
{4.3, 5.4, 5.5, 5.6, Box TS.5, TS.3.3}

B.4.3 The magnitude of feedbacks between climate change and the carbon cycle becomes larger but also more uncertain in high CO_2 emissions scenarios (*very high confidence*). However, climate model projections show that the uncertainties in atmospheric CO_2 concentrations by 2100 are dominated by the differences between emissions scenarios (*high confidence*). Additional ecosystem responses to warming not yet fully included in climate models, such as CO_2 and CH_4 fluxes from wetlands, permafrost thaw and wildfires, would further increase concentrations of these gases in the atmosphere (*high confidence*).
{5.4, Box TS.5, TS.3.2}

The proportion of CO_2 emissions taken up by land and ocean carbon sinks is smaller in scenarios with higher cumulative CO_2 emissions

Total cumulative CO_2 emissions **taken up by land and ocean** (colours) and remaining in the atmosphere (grey) under the five illustrative scenarios from 1850 to 2100

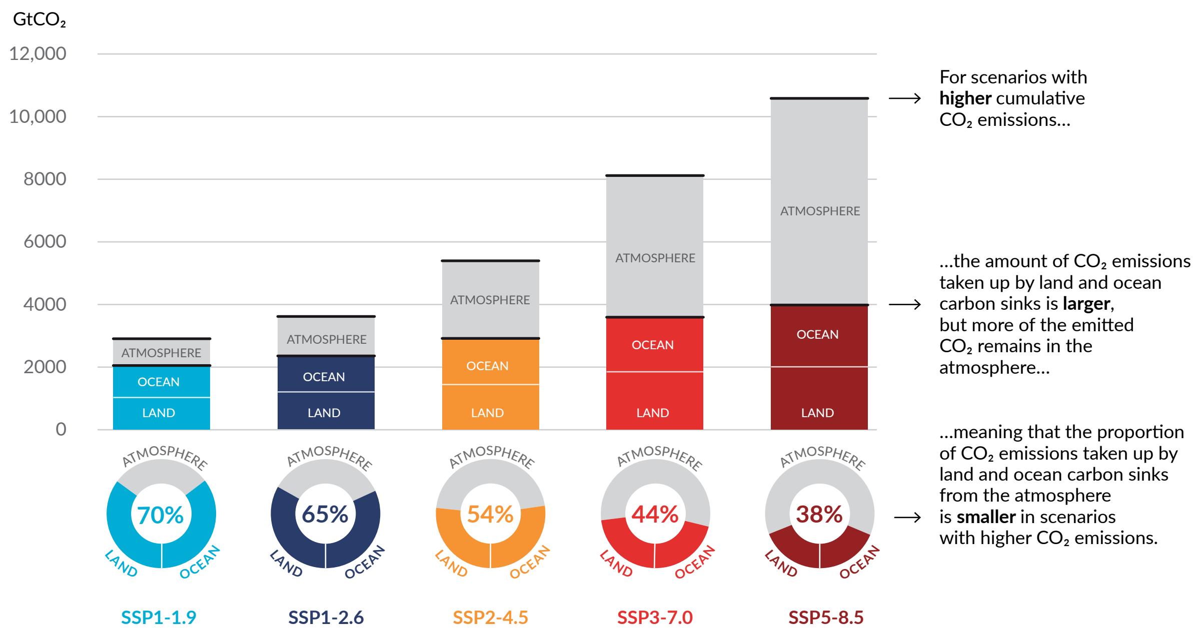


Figure SPM.7 | Cumulative anthropogenic CO_2 emissions taken up by land and ocean sinks by 2100 under the five illustrative scenarios
The cumulative anthropogenic (human-caused) carbon dioxide (CO_2) emissions taken up by the land and ocean sinks under the five illustrative scenarios (SSP1-1.9, SSP1-2.6, SSP2-4.5, SSP3-7.0 and SSP5-8.5) are simulated from 1850 to 2100 by Coupled Model Intercomparison Project Phase 6 (CMIP6) climate models in the concentration-driven simulations. Land and ocean carbon sinks respond to past, current and future emissions; therefore, cumulative sinks from 1850 to 2100 are presented here. During the historical period (1850–2019) the observed land and ocean sink took up 1430 $GtCO_2$ (59% of the emissions).

32 These projected adjustments of carbon sinks to stabilization or decline of atmospheric CO_2 are accounted for in calculations of remaining carbon budgets.

The bar chart illustrates the projected amount of cumulative anthropogenic CO_2 emissions ($GtCO_2$) between 1850 and 2100 remaining in the atmosphere (grey part) and taken up by the land and ocean (coloured part) in the year 2100. **The doughnut chart** illustrates the proportion of the cumulative anthropogenic CO_2 emissions taken up by the land and ocean sinks and remaining in the atmosphere in the year 2100. Values in % indicate the proportion of the cumulative anthropogenic CO_2 emissions taken up by the combined land and ocean sinks in the year 2100. The overall anthropogenic carbon emissions are calculated by adding the net global land-use emissions from the CMIP6 scenario database to the other sectoral emissions calculated from climate model runs with prescribed CO_2 concentrations.[33] Land and ocean CO_2 uptake since 1850 is calculated from the net biome productivity on land, corrected for CO_2 losses due to land-use change by adding the land-use change emissions, and net ocean CO_2 flux.

{5.2.1; Table 5.1; 5.4.5; Figure 5.25; Box TS.5; Box TS.5, Figure 1}

B.5 Many changes due to past and future greenhouse gas emissions are irreversible for centuries to millennia, especially changes in the ocean, ice sheets and global sea level.
{2.3, Cross-Chapter Box 2.4, 4.3, 4.5, 4.7, 5.3, 9.2, 9.4, 9.5, 9.6, Box 9.4} (Figure SPM.8)

B.5.1 Past GHG emissions since 1750 have committed the global ocean to future warming (*high confidence*). Over the rest of the 21st century, *likely* ocean warming ranges from 2–4 (SSP1-2.6) to 4–8 times (SSP5-8.5) the 1971–2018 change. Based on multiple lines of evidence, upper ocean stratification (*virtually certain*), ocean acidification (*virtually certain*) and ocean deoxygenation (*high confidence*) will continue to increase in the 21st century, at rates dependent on future emissions. Changes are irreversible on centennial to millennial time scales in global ocean temperature (*very high confidence*), deep-ocean acidification (*very high confidence*) and deoxygenation (*medium confidence*).
{4.3, 4.5, 4.7, 5.3, 9.2, TS.2.4} (Figure SPM.8)

B.5.2 Mountain and polar glaciers are committed to continue melting for decades or centuries (*very high confidence*). Loss of permafrost carbon following permafrost thaw is irreversible at centennial time scales (*high confidence*). Continued ice loss over the 21st century is *virtually certain* for the Greenland Ice Sheet and *likely* for the Antarctic Ice Sheet. There is *high confidence* that total ice loss from the Greenland Ice Sheet will increase with cumulative emissions. There is *limited evidence* for low-likelihood, high-impact outcomes (resulting from ice-sheet instability processes characterized by deep uncertainty and in some cases involving tipping points) that would strongly increase ice loss from the Antarctic Ice Sheet for centuries under high GHG emissions scenarios.[34]
{4.3, 4.7, 5.4, 9.4, 9.5, Box 9.4, Box TS.1, TS.2.5}

B.5.3 It is *virtually certain* that global mean sea level will continue to rise over the 21st century. Relative to 1995–2014, the *likely* global mean sea level rise by 2100 is 0.28–0.55 m under the very low GHG emissions scenario (SSP1-1.9); 0.32–0.62 m under the low GHG emissions scenario (SSP1-2.6); 0.44–0.76 m under the intermediate GHG emissions scenario (SSP2-4.5); and 0.63–1.01 m under the very high GHG emissions scenario (SSP5-8.5); and by 2150 is 0.37–0.86 m under the very low scenario (SSP1-1.9); 0.46–0.99 m under the low scenario (SSP1-2.6); 0.66–1.33 m under the intermediate scenario (SSP2-4.5); and 0.98–1.88 m under the very high scenario (SSP5-8.5) (*medium confidence*).[35] Global mean sea level rise above the *likely* range – approaching 2 m by 2100 and 5 m by 2150 under a very high GHG emissions scenario (SSP5-8.5) (*low confidence*) – cannot be ruled out due to deep uncertainty in ice-sheet processes.
{4.3, 9.6, Box 9.4, Box TS.4} (Figure SPM.8)

B.5.4 In the longer term, sea level is committed to rise for centuries to millennia due to continuing deep-ocean warming and ice-sheet melt and will remain elevated for thousands of years (*high confidence*). Over the next 2000 years, global mean sea level will rise by about 2 to 3 m if warming is limited to 1.5°C, 2 to 6 m if limited to 2°C and 19 to 22 m with 5°C of warming, and it will continue to rise over subsequent millennia (*low confidence*). Projections of multi-millennial global mean sea level rise are consistent with reconstructed levels during past warm climate periods: *likely* 5–10 m higher than today around 125,000 years ago, when global temperatures were *very likely* 0.5°C–1.5°C higher than 1850–1900; and *very likely* 5–25 m higher roughly 3 million years ago, when global temperatures were 2.5°C–4°C higher (*medium confidence*).
{2.3, Cross-Chapter Box 2.4, 9.6, Box TS.2, Box TS.4, Box TS.9}

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33 The other sectoral emissions are calculated as the residual of the net land and ocean CO_2 uptake and the prescribed atmospheric CO_2 concentration changes in the CMIP6 simulations. These calculated emissions are net emissions and do not separate gross anthropogenic emissions from removals, which are included implicitly.

34 Low-likelihood, high-impact outcomes are those whose probability of occurrence is low or not well known (as in the context of deep uncertainty) but whose potential impacts on society and ecosystems could be high. A tipping point is a critical threshold beyond which a system reorganizes, often abruptly and/or irreversibly. (Glossary) {1.4, Cross-Chapter Box 1.3, 4.7}

35 To compare to the 1986–2005 baseline period used in AR5 and SROCC, add 0.03 m to the global mean sea level rise estimates. To compare to the 1900 baseline period used in Figure SPM.8, add 0.16 m.

Human activities affect all the major climate system components, with some responding over decades and others over centuries

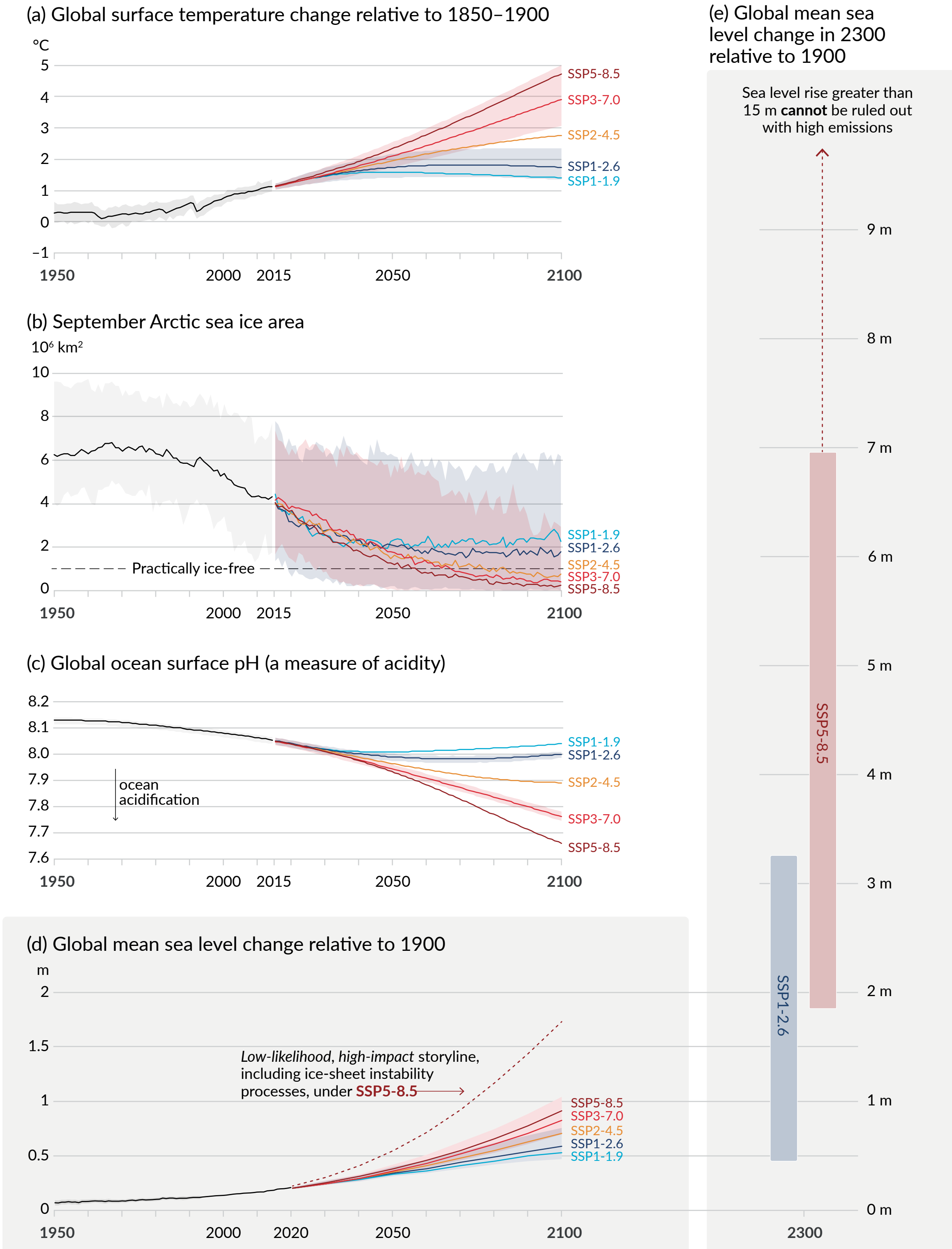

Figure SPM.8 | Selected indicators of global climate change under the five illustrative scenarios used in this Report

The projections for each of the five scenarios are shown in colour. Shades represent uncertainty ranges – more detail is provided for each panel below. The black curves represent the historical simulations (panels a, b, c) or the observations (panel d). Historical values are included in all graphs to provide context for the projected future changes.

Panel (a) Global surface temperature changes in °C relative to 1850–1900. These changes were obtained by combining Coupled Model Intercomparison Project Phase 6 (CMIP6) model simulations with observational constraints based on past simulated warming, as well as an updated assessment of equilibrium climate sensitivity (see Box SPM.1). Changes relative to 1850–1900 based on 20-year averaging periods are calculated by adding 0.85°C (the observed global surface temperature increase from 1850–1900 to 1995–2014) to simulated changes relative to 1995–2014. *Very likely* ranges are shown for SSP1-2.6 and SSP3-7.0.

Panel (b) September Arctic sea ice area in 10^6 km^2 based on CMIP6 model simulations. *Very likely* ranges are shown for SSP1-2.6 and SSP3-7.0. The Arctic is projected to be practically ice-free near mid-century under intermediate and high GHG emissions scenarios.

Panel (c) Global ocean surface pH (a measure of acidity) based on CMIP6 model simulations. *Very likely* ranges are shown for SSP1-2.6 and SSP3-7.0.

Panel (d) Global mean sea level change in metres, relative to 1900. The historical changes are observed (from tide gauges before 1992 and altimeters afterwards), and the future changes are assessed consistently with observational constraints based on emulation of CMIP, ice-sheet, and glacier models. *Likely* ranges are shown for SSP1-2.6 and SSP3-7.0. Only *likely* ranges are assessed for sea level changes due to difficulties in estimating the distribution of deeply uncertain processes. The dashed curve indicates the potential impact of these deeply uncertain processes. It shows the 83rd percentile of SSP5-8.5 projections that include low-likelihood, high-impact ice-sheet processes that cannot be ruled out; because of *low confidence* in projections of these processes, this curve does not constitute part of a *likely* range. Changes relative to 1900 are calculated by adding 0.158 m (observed global mean sea level rise from 1900 to 1995–2014) to simulated and observed changes relative to 1995–2014.

Panel (e) Global mean sea level change at 2300 in metres relative to 1900. Only SSP1-2.6 and SSP5-8.5 are projected at 2300, as simulations that extend beyond 2100 for the other scenarios are too few for robust results. The 17th–83rd percentile ranges are shaded. The dashed arrow illustrates the 83rd percentile of SSP5-8.5 projections that include low-likelihood, high-impact ice-sheet processes that cannot be ruled out.

Panels (b) and (c) are based on single simulations from each model, and so include a component of internal variability. Panels (a), (d) and (e) are based on long-term averages, and hence the contributions from internal variability are small.

{4.3; Figures 4.2, 4.8, and 4.11; 9.6; Figure 9.27; Figures TS.8 and TS.11; Box TS.4, Figure 1}

C. Climate Information for Risk Assessment and Regional Adaptation

Physical climate information addresses how the climate system responds to the interplay between human influence, natural drivers and internal variability. Knowledge of the climate response and the range of possible outcomes, including low-likelihood, high impact outcomes, informs climate services, the assessment of climate-related risks, and adaptation planning. Physical climate information at global, regional and local scales is developed from multiple lines of evidence, including observational products, climate model outputs and tailored diagnostics.

C.1 Natural drivers and internal variability will modulate human-caused changes, especially at regional scales and in the near term, with little effect on centennial global warming. These modulations are important to consider in planning for the full range of possible changes.
{1.4, 2.2, 3.3, Cross-Chapter Box 3.1, 4.4, 4.6, Cross-Chapter Box 4.1, Box 7.2, 8.3, 8.5, 9.2, 10.3, 10.4, 10.6, 11.3, 12.5, Atlas.4, Atlas.5, Atlas.8, Atlas.9, Atlas.10, Atlas.11, Cross-Chapter Box Atlas.2}

C.1.1 The historical global surface temperature record highlights that decadal variability has both enhanced and masked underlying human-caused long-term changes, and this variability will continue into the future (*very high confidence*). For example, internal decadal variability and variations in solar and volcanic drivers partially masked human-caused surface global warming during 1998–2012, with pronounced regional and seasonal signatures (*high confidence*). Nonetheless, the heating of the climate system continued during this period, as reflected in both the continued warming of the global ocean (*very high confidence*) and in the continued rise of hot extremes over land (*medium confidence*).
{1.4, 3.3, Cross-Chapter Box 3.1, 4.4, Box 7.2, 9.2, 11.3, Cross-Section Box TS.1} (Figure SPM.1)

C.1.2 Projected human-caused changes in mean climate and climatic impact-drivers (CIDs),[36] including extremes, will be either amplified or attenuated by internal variability (*high confidence*).[37] Near-term cooling at any particular location with respect to present climate could occur and would be consistent with the global surface temperature increase due to human influence (*high confidence*).
{1.4, 4.4, 4.6, 10.4, 11.3, 12.5, Atlas.5, Atlas.10, Atlas.11, TS.4.2}

36 Climatic impact-drivers (CIDs) are physical climate system conditions (e.g., means, events, extremes) that affect an element of society or ecosystems. Depending on system tolerance, CIDs and their changes can be detrimental, beneficial, neutral, or a mixture of each across interacting system elements and regions (Glossary). CID types include heat and cold, wet and dry, wind, snow and ice, coastal and open ocean.

37 The main internal variability phenomena include El Niño–Southern Oscillation, Pacific Decadal Variability and Atlantic Multi-decadal Variability through their regional influence.

C.1.3 Internal variability has largely been responsible for the amplification and attenuation of the observed human-caused decadal-to-multi-decadal mean precipitation changes in many land regions (*high confidence*). At global and regional scales, near-term changes in monsoons will be dominated by the effects of internal variability (*medium confidence*). In addition to the influence of internal variability, near-term projected changes in precipitation at global and regional scales are uncertain because of model uncertainty and uncertainty in forcings from natural and anthropogenic aerosols (*medium confidence*).
{1.4, 4.4, 8.3, 8.5, 10.3, 10.4, 10.5, 10.6, Atlas.4, Atlas.8, Atlas.9, Atlas.10, Atlas.11, Cross-Chapter Box Atlas.2, TS.4.2, Box TS.6, Box TS.13}

C.1.4 Based on paleoclimate and historical evidence, it is *likely* that at least one large explosive volcanic eruption would occur during the 21st century.[38] Such an eruption would reduce global surface temperature and precipitation, especially over land, for one to three years, alter the global monsoon circulation, modify extreme precipitation and change many CIDs (*medium confidence*). If such an eruption occurs, this would therefore temporarily and partially mask human-caused climate change.
{2.2, 4.4, Cross-Chapter Box 4.1, 8.5, TS.2.1}

C.2 With further global warming, every region is projected to increasingly experience concurrent and multiple changes in climatic impact-drivers. Changes in several climatic impact-drivers would be more widespread at 2°C compared to 1.5°C global warming and even more widespread and/or pronounced for higher warming levels.
{8.2, 9.3, 9.5, 9.6, Box 10.3, 11.3, 11.4, 11.5, 11.6, 11.7, 11.9, Box 11.3, Box 11.4, Cross-Chapter Box 11.1, 12.2, 12.3, 12.4, 12.5, Cross-Chapter Box 12.1, Atlas.4, Atlas.5, Atlas.6, Atlas.7, Atlas.8, Atlas.9, Atlas.10, Atlas.11} (Table SPM.1, Figure SPM.9)

C.2.1 All regions[39] are projected to experience further increases in hot climatic impact-drivers (CIDs) and decreases in cold CIDs (*high confidence*). Further decreases are projected in permafrost; snow, glaciers and ice sheets; and lake and Arctic sea ice (*medium* to *high confidence*).[40] These changes would be larger at 2°C global warming or above than at 1.5°C (*high confidence*). For example, extreme heat thresholds relevant to agriculture and health are projected to be exceeded more frequently at higher global warming levels (*high confidence*).
{9.3, 9.5, 11.3, 11.9, Cross-Chapter Box 11.1, 12.3, 12.4, 12.5, Cross-Chapter Box 12.1, Atlas.4, Atlas.5, Atlas.6, Atlas.7, Atlas.8, Atlas.9, Atlas.10, Atlas.11, TS.4.3} (Table SPM.1, Figure SPM.9)

C.2.2 At 1.5°C global warming, heavy precipitation and associated flooding are projected to intensify and be more frequent in most regions in Africa and Asia (*high confidence*), North America (*medium* to *high confidence*)[40] and Europe (*medium confidence*). Also, more frequent and/or severe agricultural and ecological droughts are projected in a few regions in all inhabited continents except Asia compared to 1850–1900 (*medium confidence*); increases in meteorological droughts are also projected in a few regions (*medium confidence*). A small number of regions are projected to experience increases or decreases in mean precipitation (*medium confidence*).
{11.4, 11.5, 11.6, 11.9, Atlas.4, Atlas.5, Atlas.7, Atlas.8, Atlas.9, Atlas.10, Atlas.11, TS.4.3} (Table SPM.1)

C.2.3 At 2°C global warming and above, the level of confidence in and the magnitude of the change in droughts and heavy and mean precipitation increase compared to those at 1.5°C. Heavy precipitation and associated flooding events are projected to become more intense and frequent in the Pacific Islands and across many regions of North America and Europe (*medium* to *high confidence*).[40] These changes are also seen in some regions in Australasia and Central and South America (*medium confidence*). Several regions in Africa, South America and Europe are projected to experience an increase in frequency and/or severity of agricultural and ecological droughts with *medium* to *high confidence*;[40] increases are also projected in Australasia, Central and North America, and the Caribbean with *medium confidence*. A small number of regions in Africa, Australasia, Europe and North America are also projected to be affected by increases in hydrological droughts, and several regions are projected to be affected by increases or decreases in meteorological droughts, with more regions displaying an increase (*medium confidence*). Mean precipitation is projected to increase in all polar, northern European and northern North American regions, most Asian regions and two regions of South America (*high confidence*).
{11.4, 11.6, 11.9, Cross-Chapter Box 11.1, 12.4, 12.5, Cross-Chapter Box 12.1, Atlas.5, Atlas.7, Atlas.8, Atlas.9, Atlas.11, TS.4.3} (Table SPM.1, Figure SPM.5, Figure SPM.6, Figure SPM.9)

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38 Based on 2500 year reconstructions, eruptions more negative than -1 W m^{-2} occur on average twice per century.

39 Regions here refer to the AR6 WGI reference regions used in this Report to summarize information in sub-continental and oceanic regions. Changes are compared to averages over the last 20–40 years unless otherwise specified. {1.4, 12.4, Atlas.1}.

40 The specific level of confidence or likelihood depends on the region considered. Details can be found in the Technical Summary and the underlying Report.

C.2.4 More CIDs across more regions are projected to change at 2°C and above compared to 1.5°C global warming (*high confidence*). Region-specific changes include intensification of tropical cyclones and/or extratropical storms (*medium confidence*), increases in river floods (*medium* to *high confidence*),[40] reductions in mean precipitation and increases in aridity (*medium* to *high confidence*),[40] and increases in fire weather (*medium* to *high confidence*).[40] There is *low confidence* in most regions in potential future changes in other CIDs, such as hail, ice storms, severe storms, dust storms, heavy snowfall and landslides.
{11.7, 11.9, Cross-Chapter Box 11.1, 12.4, 12.5, Cross-Chapter Box 12.1, Atlas.4, Atlas.6, Atlas.7, Atlas.8, Atlas.10, TS.4.3.1, TS.4.3.2, TS.5} (Table SPM.1, Figure SPM.9)

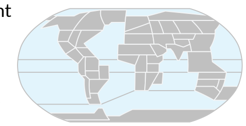
C.2.5 It is *very likely* to *virtually certain*[40] that regional mean relative sea level rise will continue throughout the 21st century, except in a few regions with substantial geologic land uplift rates. Approximately two-thirds of the global coastline has a projected regional relative sea level rise within ±20% of the global mean increase (*medium confidence*). Due to relative sea level rise, extreme sea level events that occurred once per century in the recent past are projected to occur at least annually at more than half of all tide gauge locations by 2100 (*high confidence*). Relative sea level rise contributes to increases in the frequency and severity of coastal flooding in low-lying areas and to coastal erosion along most sandy coasts (*high confidence*).
{9.6, 12.4, 12.5, Cross-Chapter Box 12.1, Box TS.4, TS.4.3} (Figure SPM.9)

C.2.6 Cities intensify human-induced warming locally, and further urbanization together with more frequent hot extremes will increase the severity of heatwaves (*very high confidence*). Urbanization also increases mean and heavy precipitation over and/or downwind of cities (*medium confidence*) and resulting runoff intensity (*high confidence*). In coastal cities, the combination of more frequent extreme sea level events (due to sea level rise and storm surge) and extreme rainfall/riverflow events will make flooding more probable (*high confidence*).
{8.2, Box 10.3, 11.3, 12.4, Box TS.14}

C.2.7 Many regions are projected to experience an increase in the probability of compound events with higher global warming (*high confidence*). In particular, concurrent heatwaves and droughts are *likely* to become more frequent. Concurrent extremes at multiple locations, including in crop-producing areas, become more frequent at 2°C and above compared to 1.5°C global warming (*high confidence*).
{11.8, Box 11.3, Box 11.4, 12.3, 12.4, Cross-Chapter Box 12.1, TS.4.3} (Table SPM.1)

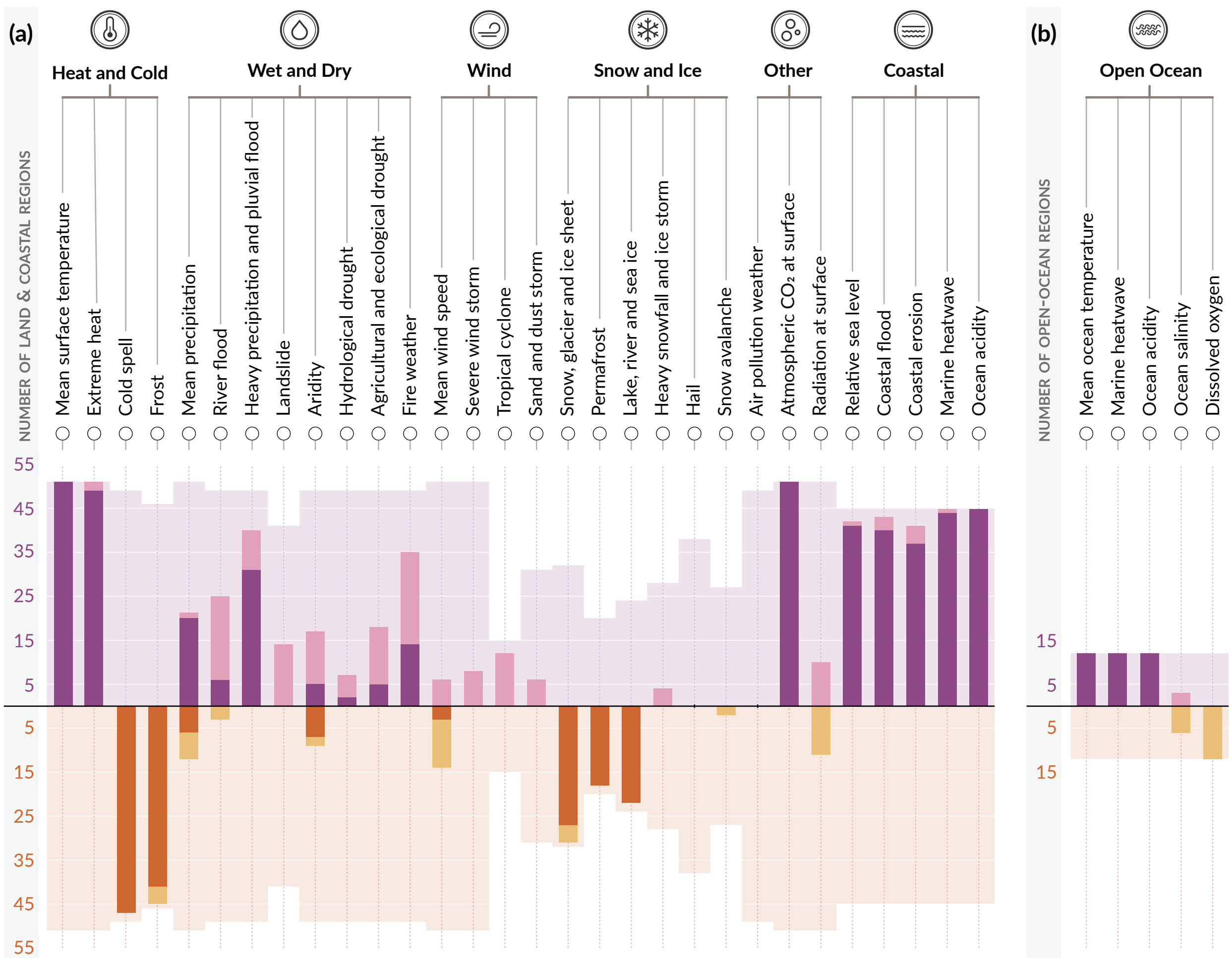
Multiple climatic impact-drivers are projected to change in all regions of the world

Climatic impact-drivers (CIDs) are physical climate system conditions (e.g., means, events, extremes) that affect an element of society or ecosystems. Depending on system tolerance, CIDs and their changes can be detrimental, beneficial, neutral, or a mixture of each across interacting system elements and regions. The CIDs are grouped into seven types, which are summarized under the icons in the figure. All regions are projected to experience changes in at least 5 CIDs. Almost all (96%) are projected to experience changes in at least 10 CIDs and half in at least 15 CIDs. For many CID changes, there is wide geographical variation, and so each region is projected to experience a specific set of CID changes. Each bar in the chart represents a specific geographical set of changes that can be explored in the WGI Interactive Atlas.



interactive-atlas.ipcc.ch

Number of land & coastal regions (a) and **open-ocean regions** (b) where each **climatic impact-driver** (CID) is projected to **increase** or **decrease** with ***high*** *confidence* (dark shade) or ***medium*** *confidence* (light shade)



BAR CHART LEGEND

- Regions with ***high*** *confidence* **increase**
- Regions with ***medium*** *confidence* **increase**
- Regions with ***high*** *confidence* **decrease**
- Regions with ***medium*** *confidence* **decrease**

LIGHTER-SHADED 'ENVELOPE' LEGEND

The height of the lighter shaded 'envelope' behind each bar represents the maximum number of regions for which each CID is relevant. The envelope is symmetrical about the x-axis showing the maximum possible number of relevant regions for CID increase (upper part) or decrease (lower part).

ASSESSED FUTURE CHANGES

Changes refer to a 20–30 year period centred around 2050 and/or consistent with 2°C global warming compared to a similar period within 1960–2014 or 1850–1900.

Figure SPM.9 | Synthesis of the number of AR6 WGI reference regions where climatic impact-drivers are projected to change

A total of 35 climatic impact-drivers (CIDs) grouped into seven types are shown: heat and cold; wet and dry; wind; snow and ice; coastal; open ocean; and other. For each CID, the bar in the graph below displays the number of AR6 WGI reference regions where it is projected to change. The **colours** represent the direction of change and the level of confidence in the change: purple indicates an increase while brown indicates a decrease; darker and lighter shades refer to *high* and *medium confidence*, respectively. Lighter background colours represent the maximum number of regions for which each CID is broadly relevant.

Panel (a) shows the 30 CIDs relevant to the **land and coastal regions**, while **panel (b)** shows the five CIDs relevant to the **open-ocean regions**. Marine heatwaves and ocean acidity are assessed for coastal ocean regions in panel (a) and for open-ocean regions in panel (b). Changes refer to a 20–30-year period centred around 2050 and/or consistent with 2°C global warming compared to a similar period within 1960–2014, except for hydrological drought and agricultural and ecological drought, which is compared to 1850–1900. Definitions of the regions are provided in Sections 12.4 and Atlas.1 and the Interactive Atlas (see https://interactive-atlas.ipcc.ch/).

{11.9, 12.2, 12.4, Atlas.1, Table TS.5, Figures TS.22 and TS.25} (Table SPM.1)

C.3 Low-likelihood outcomes, such as ice-sheet collapse, abrupt ocean circulation changes, some compound extreme events, and warming substantially larger than the assessed *very likely* range of future warming, cannot be ruled out and are part of risk assessment.
{1.4, Cross-Chapter Box 1.3, 4.3, 4.4, 4.8, Cross-Chapter Box 4.1, 8.6, 9.2, Box 9.4, 11.8, Box 11.2, Cross-Chapter Box 12.1} (Table SPM.1)

C.3.1 If global warming exceeds the assessed *very likely* range for a given GHG emissions scenario, including low GHG emissions scenarios, global and regional changes in many aspects of the climate system, such as regional precipitation and other CIDs, would also exceed their assessed *very likely* ranges (*high confidence*). Such low-likelihood, high-warming outcomes are associated with potentially very large impacts, such as through more intense and more frequent heatwaves and heavy precipitation, and high risks for human and ecological systems, particularly for high GHG emissions scenarios.
{Cross-Chapter Box 1.3, 4.3, 4.4, 4.8, Box 9.4, Box 11.2, Cross-Chapter Box 12.1, TS.1.4, Box TS.3, Box TS.4} (Table SPM.1)

C.3.2 Low-likelihood, high-impact outcomes[34] could occur at global and regional scales even for global warming within the *very likely* range for a given GHG emissions scenario. The probability of low-likelihood, high-impact outcomes increases with higher global warming levels (*high confidence*). Abrupt responses and tipping points of the climate system, such as strongly increased Antarctic ice-sheet melt and forest dieback, cannot be ruled out (*high confidence*).
{1.4, 4.3, 4.4, 4.8, 5.4, 8.6, Box 9.4, Cross-Chapter Box 12.1, TS.1.4, TS.2.5, Box TS.3, Box TS.4, Box TS.9} (Table SPM.1)

C.3.3 If global warming increases, some compound extreme events[18] with low likelihood in past and current climate will become more frequent, and there will be a higher likelihood that events with increased intensities, durations and/or spatial extents unprecedented in the observational record will occur (*high confidence*).
{11.8, Box 11.2, Cross-Chapter Box 12.1, Box TS.3, Box TS.9}

C.3.4 The Atlantic Meridional Overturning Circulation is *very likely* to weaken over the 21st century for all emissions scenarios. While there is *high confidence* in the 21st century decline, there is only *low confidence* in the magnitude of the trend. There is *medium confidence* that there will not be an abrupt collapse before 2100. If such a collapse were to occur, it would *very likely* cause abrupt shifts in regional weather patterns and water cycle, such as a southward shift in the tropical rain belt, weakening of the African and Asian monsoons and strengthening of Southern Hemisphere monsoons, and drying in Europe.
{4.3, 8.6, 9.2, TS2.4, Box TS.3}

C.3.5 Unpredictable and rare natural events not related to human influence on climate may lead to low-likelihood, high-impact outcomes. For example, a sequence of large explosive volcanic eruptions within decades has occurred in the past, causing substantial global and regional climate perturbations over several decades. Such events cannot be ruled out in the future, but due to their inherent unpredictability they are not included in the illustrative set of scenarios referred to in this Report
{2.2, Cross-Chapter Box 4.1, Box TS.3} (Box SPM.1)

D. Limiting Future Climate Change

Since AR5, estimates of remaining carbon budgets have been improved by a new methodology first presented in SR1.5, updated evidence, and the integration of results from multiple lines of evidence. A comprehensive range of possible future air pollution controls in scenarios is used to consistently assess the effects of various assumptions on projections of climate and air pollution. A novel development is the ability to ascertain when climate responses to emissions reductions would become discernible above natural climate variability, including internal variability and responses to natural drivers.

D.1 From a physical science perspective, limiting human-induced global warming to a specific level requires limiting cumulative CO_2 emissions, reaching at least net zero CO_2 emissions, along with strong reductions in other greenhouse gas emissions. Strong, rapid and sustained reductions in CH_4 emissions would also limit the warming effect resulting from declining aerosol pollution and would improve air quality.
{3.3, 4.6, 5.1, 5.2, 5.4, 5.5, 5.6, Box 5.2, Cross-Chapter Box 5.1, 6.7, 7.6, 9.6} (Figure SPM.10, Table SPM.2)

D.1.1 This Report reaffirms with *high confidence* the AR5 finding that there is a near-linear relationship between cumulative anthropogenic CO_2 emissions and the global warming they cause. Each 1000 $GtCO_2$ of cumulative CO_2 emissions is assessed to *likely* cause a 0.27°C to 0.63°C increase in global surface temperature with a best estimate of 0.45°C.[41] This is a narrower range compared to AR5 and SR1.5. This quantity is referred to as the transient climate response to cumulative CO_2 emissions (TCRE). This relationship implies that reaching net zero anthropogenic CO_2 emissions[42] is a requirement to stabilize human-induced global temperature increase at any level, but that limiting global temperature increase to a specific level would imply limiting cumulative CO_2 emissions to within a carbon budget.[43] {5.4, 5.5, TS.1.3, TS.3.3, Box TS.5} (Figure SPM.10)

Every tonne of CO_2 emissions adds to global warming

Global surface temperature increase since 1850–1900 (°C) as a function of cumulative CO_2 emissions ($GtCO_2$)

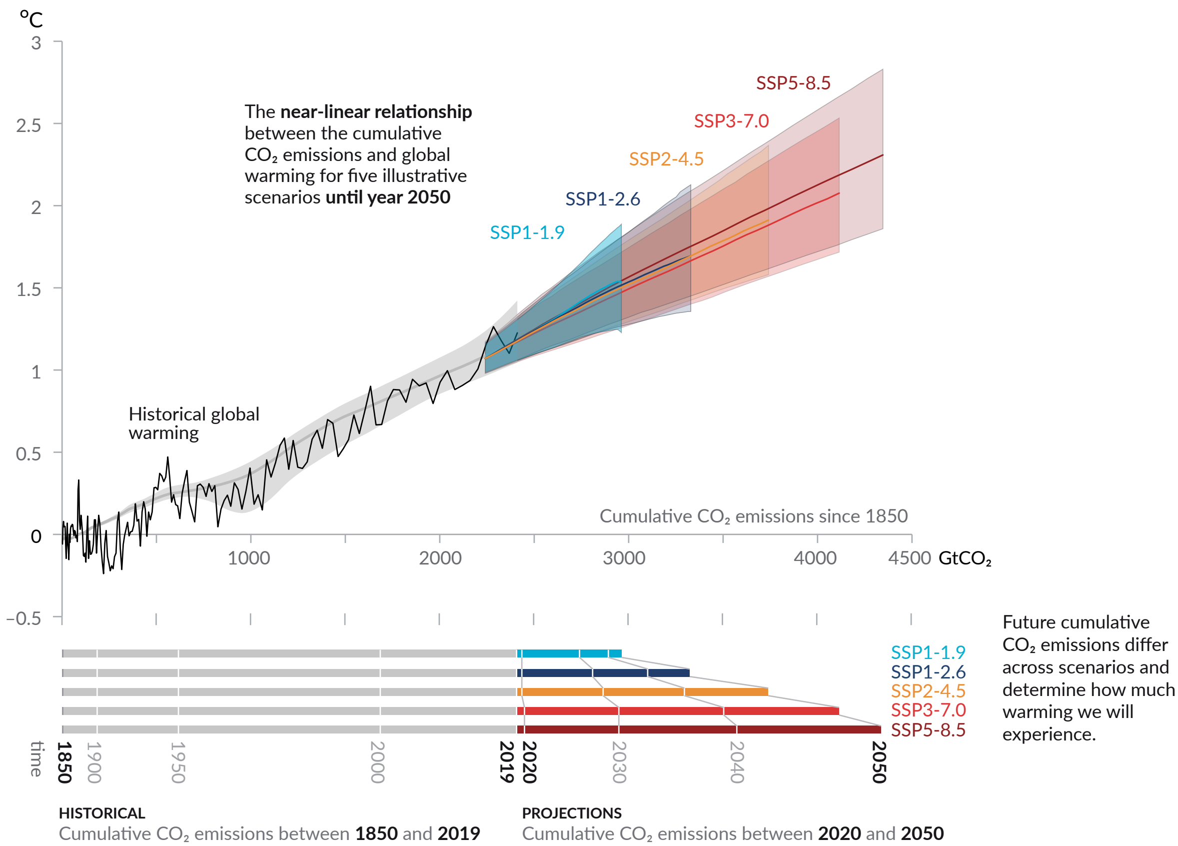


Figure SPM.10 | Near-linear relationship between cumulative CO_2 emissions and the increase in global surface temperature

Top panel: Historical data (thin black line) shows observed global surface temperature increase in °C since 1850–1900 as a function of historical cumulative carbon dioxide (CO_2) emissions in $GtCO_2$ from 1850 to 2019. The grey range with its central line shows a corresponding estimate of the historical human-caused surface warming (see Figure SPM.2). Coloured areas show the assessed *very likely* range of global surface temperature projections, and thick coloured central lines show the median estimate as a function of cumulative CO_2 emissions from 2020 until year 2050 for the set of illustrative scenarios (SSP1-1.9, SSP1-2.6, SSP2-4.5, SSP3-7.0, and SSP5-8.5; see Figure SPM.4). Projections use the cumulative CO_2 emissions of each respective scenario, and the projected global warming includes the contribution from all anthropogenic forcers. The relationship is illustrated over the domain of cumulative CO_2 emissions for which there is *high confidence* that the transient climate response to cumulative CO_2 emissions (TCRE) remains constant, and for the time period from 1850 to 2050 over which global CO_2 emissions remain net positive under all illustrative scenarios, as there is *limited evidence* supporting the quantitative application of TCRE to estimate temperature evolution under net negative CO_2 emissions.

Bottom panel: Historical and projected cumulative CO_2 emissions in $GtCO_2$ for the respective scenarios.

{Section 5.5, Figure 5.31, Figure TS.18}

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41 In the literature, units of °C per 1000 PgC (petagrams of carbon) are used, and the AR6 reports the TCRE ***likely*** range as 1.0°C to 2.3°C per 1000 PgC in the underlying report, with a best estimate of 1.65°C.

42 The condition in which anthropogenic carbon dioxide (CO_2) emissions are balanced by anthropogenic CO_2 removals over a specified period (Glossary).

43 The term 'carbon budget' refers to the maximum amount of cumulative net global anthropogenic CO_2 emissions that would result in limiting global warming to a given level with a given probability, taking into account the effect of other anthropogenic climate forcers. This is referred to as the total carbon budget when expressed starting from the pre-industrial period, and as the remaining carbon budget when expressed from a recent specified date (Glossary). Historical cumulative CO_2 emissions determine to a large degree warming to date, while future emissions cause future additional warming. The remaining carbon budget indicates how much CO_2 could still be emitted while keeping warming below a specific temperature level.

D.1.2 Over the period 1850–2019, a total of 2390 ± 240 (*likely* range) $GtCO_2$ of anthropogenic CO_2 was emitted. Remaining carbon budgets have been estimated for several global temperature limits and various levels of probability, based on the estimated value of TCRE and its uncertainty, estimates of historical warming, variations in projected warming from non-CO_2 emissions, climate system feedbacks such as emissions from thawing permafrost, and the global surface temperature change after global anthropogenic CO_2 emissions reach net zero.
{5.1, 5.5, Box 5.2, TS.3.3} (Table SPM.2)

Table SPM.2 | Estimates of historical carbon dioxide (CO_2) emissions and remaining carbon budgets. Estimated remaining carbon budgets are calculated from the beginning of 2020 and extend until global net zero CO_2 emissions are reached. They refer to CO_2 emissions, while accounting for the global warming effect of non-CO_2 emissions. Global warming in this table refers to human-induced global surface temperature increase, which excludes the impact of natural variability on global temperatures in individual years.
{Table 3.1, 5.5.1, 5.5.2, Box 5.2, Table 5.1, Table 5.7, Table 5.8, Table TS.3}

Global Warming Between 1850–1900 and 2010–2019 (°C)		Historical Cumulative CO_2 Emissions from 1850 to 2019 ($GtCO_2$)					
1.07 (0.8–1.3; likely range)		2390 (± 240; likely range)					
Approximate global warming relative to 1850–1900 until temperature limit (°C)[a]	Additional global warming relative to 2010–2019 until temperature limit (°C)	Estimated remaining carbon budgets from the beginning of 2020 ($GtCO_2$) *Likelihood of limiting global warming to temperature limit*[b]					Variations in reductions in non-CO_2 emissions[c]
		17%	*33%*	*50%*	*67%*	*83%*	
1.5	0.43	900	650	500	400	300	Higher or lower reductions in accompanying non-CO_2 emissions can increase or decrease the values on the left by 220 $GtCO_2$ or more
1.7	0.63	1450	1050	850	700	550	
2.0	0.93	2300	1700	1350	1150	900	

[a] Values at each 0.1°C increment of warming are available in Tables TS.3 and 5.8.

[b] This likelihood is based on the uncertainty in transient climate response to cumulative CO_2 emissions (TCRE) and additional Earth system feedbacks and provides the probability that global warming will not exceed the temperature levels provided in the two left columns. Uncertainties related to historical warming (±550 $GtCO_2$) and non-CO_2 forcing and response (±220 $GtCO_2$) are partially addressed by the assessed uncertainty in TCRE, but uncertainties in recent emissions since 2015 (±20 $GtCO_2$) and the climate response after net zero CO_2 emissions are reached (±420 $GtCO_2$) are separate.

[c] Remaining carbon budget estimates consider the warming from non-CO_2 drivers as implied by the scenarios assessed in SR1.5. The Working Group III Contribution to AR6 will assess mitigation of non-CO_2 emissions.

D.1.3 Several factors that determine estimates of the remaining carbon budget have been re-assessed, and updates to these factors since SR1.5 are small. When adjusted for emissions since previous reports, estimates of remaining carbon budgets are therefore of similar magnitude compared to SR1.5 but larger compared to AR5 due to methodological improvements.[44]
{5.5, Box 5.2, TS.3.3} (Table SPM.2)

D.1.4 Anthropogenic CO_2 removal (CDR) has the potential to remove CO_2 from the atmosphere and durably store it in reservoirs (*high confidence*). CDR aims to compensate for residual emissions to reach net zero CO_2 or net zero GHG emissions or, if implemented at a scale where anthropogenic removals exceed anthropogenic emissions, to lower surface temperature. CDR methods can have potentially wide-ranging effects on biogeochemical cycles and climate, which can either weaken or strengthen the potential of these methods to remove CO_2 and reduce warming, and can also influence water availability and quality, food production and biodiversity[45] (*high confidence*).
{5.6, Cross-Chapter Box 5.1, TS.3.3}

D.1.5 Anthropogenic CO_2 removal (CDR) leading to global net negative emissions would lower the atmospheric CO_2 concentration and reverse surface ocean acidification (*high confidence*). Anthropogenic CO_2 removals and emissions are partially

44 Compared to AR5, and when taking into account emissions since AR5, estimates in AR6 are about 300–350 $GtCO_2$ larger for the remaining carbon budget consistent with limiting warming to 1.5°C; for 2°C, the difference is about 400–500 $GtCO_2$.

45 Potential negative and positive effects of CDR for biodiversity, water and food production are methods-specific and are often highly dependent on local context, management, prior land use, and scale. IPCC Working Groups II and III assess the CDR potential and ecological and socio-economic effects of CDR methods in their AR6 contributions.

compensated by CO_2 release and uptake respectively, from or to land and ocean carbon pools (*very high confidence*). CDR would lower atmospheric CO_2 by an amount approximately equal to the increase from an anthropogenic emission of the same magnitude (*high confidence*). The atmospheric CO_2 decrease from anthropogenic CO_2 removals could be up to 10% less than the atmospheric CO_2 increase from an equal amount of CO_2 emissions, depending on the total amount of CDR (*medium confidence*).
{5.3, 5.6, TS.3.3}

D.1.6 If global net negative CO_2 emissions were to be achieved and be sustained, the global CO_2-induced surface temperature increase would be gradually reversed but other climate changes would continue in their current direction for decades to millennia (*high confidence*). For instance, it would take several centuries to millennia for global mean sea level to reverse course even under large net negative CO_2 emissions (*high confidence*).
{4.6, 9.6, TS.3.3}

D.1.7 In the five illustrative scenarios, simultaneous changes in CH_4, aerosol and ozone precursor emissions, which also contribute to air pollution, lead to a net global surface warming in the near and long term (*high confidence*). In the long term, this net warming is lower in scenarios assuming air pollution controls combined with strong and sustained CH_4 emissions reductions (*high confidence*). In the low and very low GHG emissions scenarios, assumed reductions in anthropogenic aerosol emissions lead to a net warming, while reductions in CH_4 and other ozone precursor emissions lead to a net cooling. Because of the short lifetime of both CH_4 and aerosols, these climate effects partially counterbalance each other, and reductions in CH_4 emissions also contribute to improved air quality by reducing global surface ozone (*high confidence*).
{6.7, Box TS.7} (Figure SPM.2, Box SPM.1)

D.1.8 Achieving global net zero CO_2 emissions, with anthropogenic CO_2 emissions balanced by anthropogenic removals of CO_2, is a requirement for stabilizing CO_2-induced global surface temperature increase. This is different from achieving net zero GHG emissions, where metric-weighted anthropogenic GHG emissions equal metric-weighted anthropogenic GHG removals. For a given GHG emissions pathway, the pathways of individual GHGs determine the resulting climate response,[46] whereas the choice of emissions metric[47] used to calculate aggregated emissions and removals of different GHGs affects what point in time the aggregated GHGs are calculated to be net zero. Emissions pathways that reach and sustain net zero GHG emissions defined by the 100-year global warming potential are projected to result in a decline in surface temperature after an earlier peak (*high confidence*).
{4.6, 7.6, Box 7.3, TS.3.3}

D.2 Scenarios with very low or low GHG emissions (SSP1-1.9 and SSP1-2.6) lead within years to discernible effects on greenhouse gas and aerosol concentrations and air quality, relative to high and very high GHG emissions scenarios (SSP3-7.0 or SSP5-8.5). Under these contrasting scenarios, discernible differences in trends of global surface temperature would begin to emerge from natural variability within around 20 years, and over longer time periods for many other climatic impact-drivers (*high confidence*).
{4.6, 6.6, 6.7, Cross-Chapter Box 6.1, 9.6, 11.2, 11.4, 11.5, 11.6, Cross-Chapter Box 11.1, 12.4, 12.5} (Figure SPM.8, Figure SPM.10)

D.2.1 Emissions reductions in 2020 associated with measures to reduce the spread of COVID-19 led to temporary but detectable effects on air pollution (*high confidence*) and an associated small, temporary increase in total radiative forcing, primarily due to reductions in cooling caused by aerosols arising from human activities (*medium confidence*). Global and regional climate responses to this temporary forcing are, however, undetectable above natural variability (*high confidence*). Atmospheric CO_2 concentrations continued to rise in 2020, with no detectable decrease in the observed CO_2 growth rate (*medium confidence*).[48]
{Cross-Chapter Box 6.1, TS.3.3}

D.2.2 Reductions in GHG emissions also lead to air quality improvements. However, in the near term,[49] even in scenarios with strong reduction of GHGs, as in the low and very low GHG emissions scenarios (SSP1-2.6 and SSP1-1.9), these improvements

46 A general term for how the climate system responds to a radiative forcing (Glossary).

47 The choice of emissions metric depends on the purposes for which gases or forcing agents are being compared. This Report contains updated emissions metric values and assesses new approaches to aggregating gases.

48 For other GHGs, there was insufficient literature available at the time of the assessment to assess detectable changes in their atmospheric growth rate during 2020.

49 Near term: 2021–2040.

are not sufficient in many polluted regions to achieve air quality guidelines specified by the World Health Organization (*high confidence*). Scenarios with targeted reductions of air pollutant emissions lead to more rapid improvements in air quality within years compared to reductions in GHG emissions only, but from 2040, further improvements are projected in scenarios that combine efforts to reduce air pollutants as well as GHG emissions, with the magnitude of the benefit varying between regions (*high confidence*).
{6.6, 6.7, Box TS.7}.

D.2.3 Scenarios with very low or low GHG emissions (SSP1-1.9 and SSP1-2.6) would have rapid and sustained effects to limit human-caused climate change, compared with scenarios with high or very high GHG emissions (SSP3-7.0 or SSP5-8.5), but early responses of the climate system can be masked by natural variability. For global surface temperature, differences in 20-year trends would *likely* emerge during the near term under a very low GHG emissions scenario (SSP1-1.9), relative to a high or very high GHG emissions scenario (SSP3-7.0 or SSP5-8.5). The response of many other climate variables would emerge from natural variability at different times later in the 21st century (*high confidence*).
{4.6, Cross-Section Box TS.1} (Figure SPM.8, Figure SPM.10)

D.2.4 Scenarios with very low and low GHG emissions (SSP1-1.9 and SSP1-2.6) would lead to substantially smaller changes in a range of CIDs[36] beyond 2040 than under high and very high GHG emissions scenarios (SSP3-7.0 and SSP5-8.5). By the end of the century, scenarios with very low and low GHG emissions would strongly limit the change of several CIDs, such as the increases in the frequency of extreme sea level events, heavy precipitation and pluvial flooding, and exceedance of dangerous heat thresholds, while limiting the number of regions where such exceedances occur, relative to higher GHG emissions scenarios (*high confidence*). Changes would also be smaller in very low compared to low GHG emissions scenarios, as well as for intermediate (SSP2-4.5) compared to high or very high GHG emissions scenarios (*high confidence*).
{9.6, 11.2, 11.3, 11.4, 11.5, 11.6, 11.9, Cross-Chapter Box 11.1, 12.4, 12.5, TS.4.3}

Rte	Desig Status (OD= Officially Designated; E= Eligible)	County	Caltrans Dist	"OD" or "E" State Scenic Highway Location (from/to)	Begin County	*Post Mile	End County	*Post Mile	Length Designated (miles)	Official Des #	Official Desig Date
33	E	Ventura	7	Route 101 near Ventura/Route l50	Ventura	0.0	Ventura	11.2			
33	E	Ven/SB/SLO	7/5	Route 150/Route 166 in Cuyama Valley	Ventura	11.2	SLO	11.5			
33	OD	VENTURA	7	FR 6.4 MI NO Route 150 TO 23.3 MI NO Route 150	VENTURA	17.6	VENTURA	34.5	16.9	32	February 18, 1972
33	OD	VENTURA	7	FR 23.3 MI NO Route 150 TO 30.5 MI NO Route 150	VENTURA	34.5	VENTURA	41.7	7.2	50	July 11, 1988
33	OD	VENTURA	7	FR 30.5 MI NO Route 150 TO 36.8 MI NO Route 150	VENTURA	41.7	VENTURA	48.0	6.3	32	February 18, 1972
33	OD	VENTURA	7	FR 36.8 MI NO Route 150 TO SANTA BARBARA CL	VENTURA	48.0	VENTURA	57.5	9.5	50	July 11, 1988

**Post Miles for eligible segments are approximate; legal limits of State Scenic Highways are described in the Streets Highways Code (For limits of federal byways, visit FHWA "America's Bways" or USFS Scenic Byway programs).*

Note:

Postmiles provided for eligible segments througout this spreadsheet are approximate. If any dicrepancy exists between the spreadsheet postmiles and the text description in the Streets and Highways Code, the SHC text prevails.

Notes about updates:

October 2015	State Route 180, Fresno County, added as OD
February 2016	State Route 52, in San Diego, added as OD
December 2016	*Gaviota Coast State Scenic Hwy* added as OD
March 22, 2017	*Topanga Canyon State Scenic Highwa* y added as OD
March 2017	Official Designation Dates added to this collated spreadsheet (which shows "E" and "OD" routes).
August 2017	Formatting change: begin/end county postmiles separated into separate columns.
October 2018	Note added in footer "post miles are estimates;" legal limits are described in CA SHC.
July 2019	Route 128 (entire length) added to eligibility list by legislation (AB 998)